Service Date: October 3, 1991

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF The Application	)	UTILITY DIVISION
Of the MONTANA POWER COMPANY for	)	
Authority To Establish New Rates	)	DOCKET NO. 90.1.1
Required to Implement its Gas	)	
Transportation Plan.	)	ORDER NO. 5474c

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<u>FINAL ORDER</u>

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BEFORE:

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FINDINGS OF FACT

I. BACKGROUND

A. INTRODUCTION

General

This matter before the Montana Public Service Commission (PSC or Commission) is a formal consideration of a comprehensive proposal for natural gas transportation by Montana Power Company (MPC or Company). The proposal would substantially change the way MPC has traditionally been organized to provide natural gas services to its customers and, for certain classes of customers, the way in which it has traditionally provided natural gas services.

This Docket was formally commenced on January 10, 1990, through application of MPC. It was preceded by the PSC's unresolved first consideration of transportation by MPC in PSC Docket No. 87.8.38, dismissed on request of MPC with direction that MPC file again. See, PSC Docket No. 87.8.38, Order No. 5409, May 15, 1989. MPC's present filing satisfies that Order.

The primary driving force behind this plan is that MPC's traditional natural gas service design appears to be unsuitable to reasonably meet a real threat of bypass and the probable adverse effects of bypass for MPC and its remaining customers -- increased rates, all other things remaining equal, to absorb the overall costs of a system formerly shared by the customer or customers bypassing.

By way of general introduction, MPC's comprehensive transportation plan proposes new rates and rules of service applicable to both a traditional fully-bundled service to "core" customers and a new unbundled range of optional services to "noncore" customers.

In a fully-bundled service (MPC's traditional and present service) the total of procurement, production, processing, storage, supply, transmission, delivery, and all other related aspects of natural gas service are a package to the customer -- MPC provides natural gas as a product and service to the customer's burner tip. This type of service would be retained in MPC's plan for "core" customers, including residential, small general service, and some others.

In an unbundled service one or more or all of the elements of a fully-bundled service become separable. Qualifying customers can choose to take one or more services only. This, in addition to other benefits, would allow MPC to compete to meet the threat of bypass by offering less costly separate services such as transportation. The benefit to MPC and its remaining customers would be that the system costs would continue to be shared, albeit to a lesser extent, by that customer or those customers who would otherwise have bypassed.

The unbundling of services would also permit MPC to provide natural gas transportation -- the service of moving natural gas from one point to another on its system. This ability is not entirely foreign to MPC as it has held Hinshaw pipeline status since 1956 and has recently obtained "Order 63" status from the Federal Energy Regulatory Commission (FERC).

Procedure

MPC's January 10, 1990 application was followed by the PSC's January 23, 1990 Notice of Application and Prehearing Conference. Intervention was subsequently granted to approximately 50 parties. Of these, the active intervenors are the Montana Consumer Counsel (MCC), Great Falls Gas Company (GFG), Stone Container Corporation (SCC), District XI Human Resource Council (HRC), Montana Department of Social and Rehabilitative Services (SRS), Montana Department of Natural Resources and Conservation (DNRC), Montana Refining Company (MRC), and Montana Oil and Gas Association (MOGA).

MPC's January 10, 1990 filing has been amended by several subsequent filings and occurrences. As initially filed the proposed rate schedules were based on adjustments made in PSC Docket No. 88.6.15, MPC's then-most-recent general rate case. On June 27, 1990 MPC filed a new general rate case, PSC Docket No. 90.6.39, which then formally became the basis for rate schedules and through which, on July 19, 1991, the PSC established the revenue requirement for natural gas rates in this docket. See, PSC Docket No. 90.6.39, Order No. 5484k. MPC also amended its initial filing on two occasions, one on October 9, 1990, and one on February 12, 1991. These amendments have been considered and approved. The amended material remains a part of the record for comparative or historical purposes. The details are immaterial for purposes of this Order.

The active parties proceeded through discovery and prefiling of testimony and replies. On March 15, 1991 the PSC issued a Notice of Public Hearing. Satellite hearings were held in Billings, Missoula, Great Falls, Townsend, Shelby, and Helena. Hearing convened before the PSC on April 30, 1991 and adjourned on May 10, 1991. A briefing schedule was established.

After the conclusion of the hearing, all active parties, except MRC and MOGA, met several times for settlement negotiations and produced an agreement disposing of issues among themselves. This agreement adopts MPC's gas transportation plan with modifications, primarily for the purpose of implementation. It was submitted to the PSC as a Stipulation Agreement (Stipulation). MRC, although not a party to the negotiations, supports the agreement. MOGA remains opposed to it. The Stipulation is attached as Appendix 6.

The PSC has reviewed and analyzed the Stipulation and determines that it shall be a basis for this Order. However, in the absence of unanimity of the active parties, it cannot be a substitute for this Order. MOGA remains an active party to this proceeding, remains opposed to the transportation plan and the Stipulation, and is entitled to a reasoned response to its position on the merits.

B. DISCUSSION

Arguments Supporting Gas Transportation

The production of natural gas has been generally recognized as a sector of the natural gas industry that is naturally competitive. The ownership and operation of gas transmission and distribution pipelines, however, are not naturally competitive. These sectors of the market place remain natural monopolies.

The federal government has recognized the competitive nature of the sale of natural gas field supplies and has taken the lead in deregulation of wellhead prices. In 1978, Congress enacted the Natural Gas Policy Act (NGPA) which expressly removed the FERC's Natural Gas Act (NGA) jurisdiction over prices for new gas supplies. 15 U.S.C. 3431 (1982). The NGPA also limited FERC's jurisdiction to review the purchase costs of such new gas by pipelines at the city-gate. 15 U.S.C. 3431(c) (1982). Another key provision of the NGPA is Section 311, which authorizes the FERC to allow interstate and intrastate pipelines to transport gas in interstate commerce without being subject to the Section 7 certificate and abandonment requirements of the NGA.

In 1985, FERC implemented procedures to promote open access transportation by interstate pipelines, set forth in FERC Order No. 436, which was modified later by FERC Order No. 500. The genesis of FERC Order No. 436 was the result of two decisions of the United States Court of Appeals of the District of Columbia (Maryland People's Counsel v. FERC, "Maryland I and II"). In Maryland I and II, the Court struck down FERC's approval of discriminatory transportation programs, called Special Marketing Programs (SMPs), and remanded to FERC for review. FERC issued Order No. 436, which, among other things included a transportation program which required nondiscriminatory access.

Through legislation and FERC orders and decisions, the interstate natural gas industry has been transformed from a fully bundled regulated business to an unbundled transportation and sales business with companies transporting gas for shippers for a fee. This process is still evolving. See, Notice of Proposed Rulemaking, FERC Docket No. RM91-11-000 (July 31, 1991).

The deregulation of U.S. natural gas production has played a significant part in the fall of natural gas prices across the U.S. and Canada. Certain MPC customers have less costly alternatives to the gas supply available from MPC's system.

GFG, an MPC utility customer, testified and publicly announced that it would build a pipeline to other sources of supply if gas transportation was not made available on MPC's system. GFG has studied the cost savings over the past several years and determined it could save approximately $2 million per year over present rates if it built its own pipeline and bypassed MPC's status quo system. GFG also testified that access to low-cost supplies, through gas transportation, could permit it to increase its market, thus further decreasing costs to its customers. GFG further testified that even if MPC made a special discount rate available to GFG, this option would not be as attractive to it as transportation service because, in its view, the discount rate option leads to a death spiral in the gas business.

Some of MPC's large industrial customers also have alternative fuel opportunities which have caused MPC to implement a special rate, the Interruptible Market

Retention (IMR) rate, to stave off further load losses. Competition from alternative fuels such as coal, petroleum products, propane, and hog fuel has been an increasingly significant factor in the way MPC has run its business in the last several years.

SCC has testified that it would bypass because of high prices on the MPC system and because it has alternatives if unbundled, nondiscriminatory transportation rates are not offered.

MPC is concerned about continuing to offer discounted rates to large industrial customers to keep those customers on its system. Such action may pose some risk for a challenge of discrimination or of a claim of violation of antitrust statutes. Such challenges were made in the Maryland I and II cases cited above.

DNRC testified that bypass also leads to inequities. By-pass not only shifts costs, but it leads to inequities among consumers and producers. For consumers, the inequity is that bypass by a few large customers adversely impacts remaining cus tomers and, to the extent inequities will exist, can be avoided.

If GFG were to bypass, MPC would lose approximately 4 Bcf/year of load from its present market. If interruptible industrial customers and other large customers also bypassed MPC's system, there could be loss of another 3 BCF/year. The combined loads of GFG, the interruptible industrial customers and other large customers represent about one-fourth of MPC's current annual sales market.

MPC presented a study in its original January, 1990 filing which compared business-as-usual with a bypass scenario. In the business-as-usual case, MPC made several assumptions, including using operating expenses presented in Docket No. 88.6.15

in the first year of the analysis and assuming IMR and NGI sales would continue at the then-current volumes and escalating prices. The forecast of the Base Case core customer unit revenue requirements showed a core unit revenue requirement increase from $4.09/Mcf (in effect at the time of the study) to $6.49/Mcf by the tenth year.

For the Bypass Case, MPC assumed that GFG and SCC would bypass MPC's system and deducted the volumes included for GFG (4.2 BCF) and SCC (2.3 BCF) from the Base Case total sales market. MPC's royalty gas takes were reduced to fit the new smaller requirements because of royalty gas flexibility and because the consequence of not taking purchased gas at the take-or-pay level, is paying for it anyway.

The first year core customer unit revenue requirement in the Bypass Case was $4.92/Mcf and over ten years rose to $6.83/Mcf. The impact of bypass to core customers in the first year was estimated to be an immediate increase of $0.83/Mcf from $4.09/Mcf (in the Base Case) to $4.92/Mcf (in the Bypass Case).

If bypass occurred, the resulting system gas cost would be higher because either production of low unit cost royalty gas would be reduced or purchased gas would be reduced, causing take-or-pay liability costs.

Additionally, fixed costs can be reallocated to the remaining customers when bypass occurs. Once a customer invests in a bypass pipeline or an alternative fuel system, its gas volumes, and the potential for any contributions to fixed costs, are lost to the MPC system.

If bypass occurred, as proposed by GFG, less gas would be shipped through the MPC system but fixed costs could stay virtually the same. Additionally, regardless of who shoulders the burden, the result would be an uneconomical duplication of pipeline transmission service because there is already capacity on MPC's system to handle such a transaction.

No testimony revealed that bypass by GFG and SCC was not a real and imminent threat to business as usual. Therefore, it appears highly probable that those customers will bypass if gas transportation is not implemented.

The evidence presented other unrefuted reasons for implementing gas transportation. Competition in gas procurement brought about by open access transportation will provide MPC with the clearest indication and signal of what is the lowest market-competitive price at which it can procure gas for core customers. It will also provide the greatest range of opportunities for procuring gas and will give the Commission the best indicator of how effectively MPC is providing for the interests of the core customers.

Like many utilities in this country, MPC is faced with an extremely low market load factor; it experiences an extremely high winter peak but low average daily loads. This translates into inefficient pipeline utilization. Transportation will provide MPC the opportunity to improve pipeline utilization and use its capital investment in facilities more efficiently. The revenue MPC collects as a result of incremental transportation business would help offset the fixed costs of transmission and thus benefit all core and firm transportation customers.

Gas transportation is preferable to the bypass scenario because those customers using the transportation service will, through their transportation rate, contribute to the fixed costs of the transmission system, a contribution that otherwise would be foregone if those customers bypass.

Another benefit of MPC's plan is that the risk of obtaining and maintaining gas supplies for large customers who may leave the system at any time would be eliminated. MPC's overall objective includes shifting its utility service obligation to noncore customers from "sales" to "transportation" and shedding the gas supply burden and risk. This objective was one reason for designating customers as core or noncore customers. These designations specifically define MPC's service obligations to the various customer classes and ultimately result in MPC's obligation to serve being more clearly defined. Previous one-sided obligations would be eliminated -- MPC would have no obligation to supply gas to noncore customers who have no corresponding obligation to take the gas or otherwise pay for it.

Gas transportation would allow MPC to unbundle its services. Unbundling supply, storage, transmission, and distribution services would have two types of benefits. First, it would allow consumers the choice of buying only the services they need. Currently, all of MPC's customers are offered only the bundled gas commodity. With the offering of unbundled services, customers could buy the services they require without having to buy other unneeded services. Second, unbundling would allow a closer matching of customers and costs. Costing individual services provided by MPC and pricing them separately would allow the costs of each service to be paid by the customers who use them.

Montana's gas producers would also benefit from gas transportation. Many Montana gas producers now have no choice except to sell their production to MPC. If MPC's pipeline system is opened for nondiscriminatory transportation, Montana producers would have the opportunity to sell their gas to the highest bidder either on or off the system. Gas prices are higher in many other parts of the U.S., and Montana producers could benefit from being able to reach a wider market.

Response to MOGA Brief

MOGA is the only active intervenor that has opposed gas transportation, arguing that it was not in the public interest. MOGA is also the only active participant in Docket No. 90.1.1 that did not participate in the negotiation of or sign the Stipulation or otherwise approve of it. In its Reply Brief, MOGA requested that the "... referenced Stipulation Agreement be stricken and expunged from the record in its entirety" because it introduced new evidence into the record after the prescribed time for submission of such evidence had expired. MOGA contended it was "egregiously excluded from attending" the settlement discussions and "is compelled to forfeit its right to rebuttal" if the Commission accepts the Stipulation.

The Stipulation was filed on June 28, 1991, the date the initial briefs of the parties were due. MOGA had the opportunity to address the Stipulation in its reply brief, which it did. Also, a settlement conference regarding the proposed Stipulation was noticed by the Commission and held on July 30, 1991. The parties to the Stipulation were available and subject to questioning. Members of MOGA did not appear, although MOGA's attorney and many individual MOGA members who are on the service list in Docket No. 90.1.1 were notified. MOGA expressed to the PSC that it missed the Stipulation meeting inadvertently. MOGA has not been compelled to forfeit its right of rebuttal but instead has had sufficient opportunity to be heard.

The Commission finds that MOGA's case has been heard in its entirety by this Commission and has been heeded. Because MOGA is the only party that opposed gas transportation in principal and because, in MOGA's words, the Stipulation "... in no way addresses the over-all merits of gas transportation as proposed," it is the Commission's opinion that MOGA has had opportunity and has availed itself of that opportunity to be heard on the policy issue of gas transportation.

The Commission further determines that MOGA had no legal right to attend the negotiation meetings as they were voluntary meetings and those participating had the right to invite and negotiate with the parties they chose.

The Commission finds that the Stipulation does not introduce new evidence into the record. The Stipulation is merely a supplementing modification of MPC's plan resolving contested issues among the participating parties. The parties have agreed to undertake certain matters on their own, such as assignment of gas purchase contracts and the agreement by GFG to remain a nontransporter for portions of its annual loads over a transition period. The resulting rates are well within the acceptable range of rates the Commission could have ordered, based on the evidence in the record. MOGA did not propose any alternative or compromise plan for gas transportation, instead opting to oppose gas transportation per se as being in violation of sound public policy. Therefore, the Commission finds that MOGA has not been harmed in any relevant or actionable way by the presentation of the Stipulation.

Gus B. Coolidge, Jr., testifying on behalf of MOGA, stated that the MPC system is a distribution system and not a transportation system. As such, he claimed it is not capable of transporting gas in excess of its current load on an annual basis and does not qualify as an "open access" system, as defined by FERC. He stated that Montana gas producers will not have firm capacity available and, therefore, will not be able to achieve the best price for their gas in off-system markets since they will only be able to sell interruptible gas. Mr. Coolidge referred to this problem as "producer bypass."

The solutions suggested by Mr. Coolidge were that the Commission require MPC to provide firm capacity for access to potential off-system markets for all Montana gas that is displaced by Canadian gas and to require implementation of open access according to FERC Order 500. The other alternative he suggested was that the Commission deny gas transportation as a violation of good public policy.

According to MOGA, Montana producers require a facility that is capable of moving a definite volume of gas on a year-round basis. They believe there is no market for interruptible deliverability, and they believe they cannot compete with Canadian gas on the spot market because the production costs in Mon tana are higher due to the formation of the reservoirs and the additional compression required to deliver it.

Much of MOGA's concern is that if its members are forced to compete for off-system markets, they are too far from the load centers. Mr. Coolidge testified that,

> ... geographically it is a disadvantage as well. We're kind of at the end of the road here. In other words, in order to get to some potential markets we may have to go through two or three systems. By the time you pay the transportation charges on the Montana Power Company plus somebody else to reach that other market, you may be looking at a very, very small net back. (Tr. pp. 1197, 1205-1206).

It is MPC's position that gas transportation will benefit Montana gas producers. Dr. Tussing testified that, in a competitive environment, producers should have available to them an open-ended set of purchasers such as interruptible industrial users, LDC's, pipeline companies, and unregulated marketers of gas. This competition should allow the producers to achieve the best possible price for their gas supplies.

MPC argued that, after open-access transportation is implemented, it would begin to make more capacity available if it was economically and operationally justified. In MPC's gas transportation plan, consistent with FERC policy, open-access means that parties other than MPC would have an equal and nondiscriminatory opportunity to transport through the space available on its pipeline system. Open access does not mean that MPC would provide unlimited capacity so that any and all parties have an absolute right to transport all the gas they have available through the pipeline. In that respect, MPC's gas transportation plan would provide Montana producers access that is equal to that provided to all other producers. MPC has the ability to add more capacity as it is required, if it is required.

MPC's transmission lines are connected to the NOVA trunkline at the Canadian border in the northwest, affording access to virtually any gas source in Alberta, Canada. In the northeast an Enron system that ultimately connects with TransCanada

Pipeline in Canada constitutes another link with the producing areas of Alberta, and also a potential outlet (or source) for Montana gas to the midwestern U.S. and central Canada. In the southeast, MPC's lines connect with Williston Basin Interstate (WBI) Pipeline and potentially with markets in the Midwestern and Gulf States.

Mr. Johnson testified that MPC has an agreement in place with Colorado Interstate Gas (CIG) to pursue an interconnection between the two companies' pipeline systems. If the connection is made, it would provide a through-way for Canadian or Montana gas moving to markets south of Montana. It would also provide a tailor-made potential for backhauls on the MPC system. It is unclear at this time the extent to which this transportation would be firm.

The WBI connection also provides for a backhaul opportunity. In fact, all the pipeline interconnections discussed in previous findings are with open-access pipeline systems and back haul situations conceivably exist at each connection, if markets are available. Dr. Tussing testified that facilities that have become open access have experienced a quantum increase in effective pipeline capacity:

> It is my general view that neither the utility nor people looking from the outside can fully appreciate the benefits that will come about. I suspect that the utility is unreasonably pessimistic about how much gas it can carry over its facilities once it's opened up. There are a lot of parties looking at ways in which the effective capacity could be increased by exchanges or displacements or new hookups. (Tr. p. 265).

MPC testified that it would work with interested shippers and that interconnections or expansions would be made as they are specifically demanded, long-term contractual transportation commitments are made, and their cost-effectiveness and need is studied and proven. MPC argued that it is unreasonable for the Commission to deny open-access because the system is not yet at its maximum capabilities. The first step is to establish an open-access transportation policy; increased capacity will follow. The uncontroverted testimony of Dr. Tussing related,

> What has happened throughout the United States is that there has been a hundred-fold increase in interconnections between pipelines and utilities and among utilities, but most of those wouldn't have come about if there hadn't been open access, the deregulation of gas prices, and the end of regulatory dedication. (Tr. p. 263).

Virtually all of the natural gas presently capable of production in MPC's service area in Montana which is not owned by MPC (approximately 12.5 Bcf/year) is presently connected to the MPC system and is purchased by MPC. There is little or no shut-in Montana gas seriously seeking transportation on MPC's system at this time. MPC has stated its intention to continue to honor those purchase contracts and will discuss renewals or extensions with Montana producers, when appropriate, to supply gas for its continuing obligation to secure supplies for the core market. Montana producers will have a reasonable amount of time to evaluate new, alternative markets before their contracts expire and make reasoned choices about continuing sales to MPC.

MPC argued that Montana producers have a clear opportunity to compete for Montana markets, both the noncore transportation market and the core, MPC market. All present noncore customers of MPC have been allocated firm pipeline capacity consistent with their needs on peak day and, therefore, acquiring capacity would not be a problem for a producer who contracts with these noncore customers. Montana producers will have the advantage over out-of-state suppliers for the Montana market because they are already connected to MPC's transportation system. Their proximity to the service area alleviates the need for a purchaser to contract for transportation service in addition to MPC's transportation service, as will be necessary if gas supply is purchased from off-system. Dr. Tussing testified,

> It would cost at least 20 cents, if not more, to get Alberta gas to the border, so that Montana gas should always have a competitive advantage over Alberta gas. But it's Alberta gas that will assure that the market is competitive and provide the benchmark competitive price. But it would still seem to me Montana gas is physically the most critical element. (Tr. p. 287).

MOGA testified that its gas is long-term and reliable. This superior product will give it an additional advantage over spot gas from Alberta when it competes for noncore markets and especially for the MPC core market, because that quality of gas is required to serve residential customers. The Montana producers have competed successfully with other production to this time and so should rely on their ability and business expertise to continue to be able to provide service to the Montana market.

Montana producers must also compete with Alberta gas under the business-as-usual scenario. MPC is not compelled to purchase Montana-produced gas if it has access to equally reliable, but less expensive, sources. If open access were denied and MPC chose not to renew purchase contracts with the Montana producers as the existing contracts expire, for whatever reason, then Montana producers would have no alternative than to shut-in their production. Gas transportation would provide Montana producers with an opportunity to access new markets so they are not totally dependent on the Montana market, which has no corresponding obligation to purchase from them.

Montana producers can take immediate advantage of the interruptible transportation that is presently available on the MPC system. Given that MPC already has all present production tied up on a firm basis, these sales would be sales for incremen tal amounts of production. There are markets for interruptible gas both in and out of Montana, e.g., SCC or supply aggregators.

C. COMMISSION FINDINGS

The Commission finds that open access gas transportation on MPC's system is in the best interest of all parties in Docket No. 90.1.1 and of the general public of the State of Montana.

The Commission finds that federal legislation and FERC deregulation have transformed the natural gas industry from a fully-bundled, regulated business to an unregulated supply business with an unbundled, but regulated, transportation business. The deregulation of natural gas production has played a role in the fall of natural gas prices across the U.S. and Canada and, as a result, many MPC customers may have less costly gas supply available to them than is available from MPC. Customers also have other fuel supply sources available that are less expensive than fully-bundled service from MPC.

The Commission finds that the evidence presented in this Docket supports the contention that GFG and SCC could bypass the MPC system if gas transportation is not implemented at this time. The consequences of bypass by these two customers on the remaining core customers would be significant and should be avoided. The remaining customers could be left with an increased share of the fixed costs of the system and the gas cost component of their rate could rise due to lower proportionate use of royalty gas and/or purchased gas take-or-pay liability, until the gas supply could be adjusted to fit the smaller market. The core unit revenue requirement cost impact could be as much as \$0.83/Mcf in the first year.

The Commission finds that bypass by GFG could constitute "uneconomic" bypass and therefore result in an uneconomic use of resources. Construction of a pipeline by GFG would duplicate services already available on MPC's system. Therefore, business as usual is undesirable because it might result in uneconomic bypass.

The Commission finds that gas transportation is a positive way to avoid uneconomic bypass, superior to present practices, such as discounting rates for certain customers.

The Commission finds there are several other benefits of gas transportation in addition to avoiding the impacts and problems of bypass. Gas transportation will allow the market place to determine the appropriate price of natural gas in Montana. It will provide increased supply options for many gas users. Gas transportation also provides the opportunity for MPC to more fully utilize its pipeline system, thus contributing additional revenue to offset fixed transmission costs for core and noncore customers.

Gas transportation provides the additional benefit of alleviating MPC's risk of providing gas supply for large customers that have no corresponding obligation to purchase that sup ply. The Commission finds MPC's obligation to serve noncore customers would be satisfactorily achieved by providing transportation or sales subscription service, as defined herein.

The Commission has considered the Montana producers' arguments against gas transportation, and while the Commission is mindful of the producers' concerns, it is of the opinion that gas transportation will eventually lead to a better resolution of those concerns than will business-as-usual.

MOGA assumes that Alberta gas will automatically replace all Montana gas if gas transportation is allowed. The Commission believes this is unlikely. The Montana producers are already in competition with Alberta gas because, although MPC's customers do not presently have direct access to Canadian sources of supply, MPC does. Montana producers currently sell all of their production to MPC. In the future, MPC should look to Alberta or elsewhere for long-term, reliable sources of supply only if the Montana producers fail to aggressively market their gas on competitive terms.

The Commission believes today's business-as-usual scenario is a potentially inequitable situation for Montana producers because MPC has the opportunity to go to other suppliers for its gas supply but the Montana producers do not have the same opportunity to sell their supply to others. Gas transportation and open access will provide opportunity to correct that inequity.

The Commission also believes that the Montana producers will be in a good position to compete for the noncore customer market. The fact that GFG and SCC were willing to accept assignment of certain long-term purchase contracts (explained later, FOF

138, 139 and 143) indicates a willingness to do business with Montana producers. Again, Montana producers must be competitive with other gas suppliers but will have an advantage in Montana because of their location and present gathering systems.

The Commission finds that the Gas Transportation Plan adopted herein, in conjunction with the "Order 63 Certificate" issued by FERC, provides Montana producers equal access to interruptible transportation service relative to all other shippers, including those from Canada. The Commission will not order and MPC should not provide Montana producers any preference to pipeline space, as such a practice can be discriminatory, contrary to the very spirit of open access transportation.

The Commission understands that Montana producers may be able to receive a higher price for their gas supplies if there were year round pipeline capacity available on MPC's system to transport the Montana producers' supplies. On the other hand, the Commission realizes MPC should not make pipeline capacity additions that are not financially prudent. The Commission, therefore, finds MPC should make investments necessary to increase the available capacity on the system to the extent those investments are prudent and cost effective. Further, the Commis sion encourages MPC and Montana producers to jointly identify creative backhaul and displacement opportunities to enhance the effective pipeline capacity. MPC should work with Montana producers to identify necessary cost effective improvements. MPC should demonstrate in the annual filings which are approved by this Order that it has undertaken the above activities.

The Commission understands that one of MOGA's concerns is that its gas supply might be too far from load centers and therefore it may not be economically beneficial to compete in those markets. However, the Commission notes that Montana production is closer to markets south of Montana than is Canadian production. It is also the Commission's opinion that the transportation cost to other markets would be a problem whether or not Montana producers have access to year-round capacity on MPC's system.

II. GAS TRANSPORTATION PLAN - SUMMARY

MPC's transportation proposal was modified and amended over the course of Docket No. 90.1.1. The proposal presently before the Commission for consideration is a collection of features presented throughout the Docket. This section of the Commission's order describes, in summary form, the features of the transportation plan combined from the record into the Stipulation.

A. CORE/NONCORE DISTINCTION

The Transportation Plan defines two customer types -- core and noncore. Noncore customers include "all Interruptible Industrial Gas Contract Customers; other Utility Customers and large General Service Customers whose annual consumption exceeds 60,000 Mcf per facility." The effect of this noncore definition is to include all present FUGC customers in the noncore group except the Town of Kevin and Treasure State Pipeline (<u>see</u> FOF 76 for new FUGC "core" treatment option). Additionally, all general service customers served by MPC whose 1989 test year consumption exceeded 60,000 Mcf and all interruptible industrial customers, regardless of their consumption level, would be noncore. Core customers are those customers who do not meet the noncore customer definition.

Under the Plan, noncore customers would have service options that core customers do not. Noncore customers would have the option of buying gas from MPC on a bundled basis or of procuring their own gas supplies and transporting gas on MPC's system. Core customers would not have a transportation option and could only purchase fully bundled sales service.

B. NONCORE CUSTOMER GROUPS

Noncore customers are divided into two groups based on their present customer class and their basic business interests. Those noncore customers presently taking service in the FUGC class are noncore local distribution companies that sell gas largely to customers who would be considered core customers if they were customers of MPC. These noncore local distribution companies will be referred to herein as noncore FUGC customers. The remaining noncore customers presently taking service in the general service or interruptible industrial classes for their own consumption will be referred to herein as noncore "end users."

C. TRANSITION PERIOD

The plan calls for a three-year transition period during which noncore customers would be able to make a transition from initial service options to other service options. The transition years are defined to approximately coincide with the traditional MPC gas cost tracking year. The first transition year (year 1) is defined as the period beginning on the date of transportation implementation and ending on August 31, 1992, even though that period will not cover a full year. The second transition year (year 2) would be the year beginning September 1, 1992 and ending August 31, 1993; and the third transition year (year 3) would be the year beginning September 1, 1993 and ending August 31, 1994. During the transition period, customer service options will be restricted to accommodate an orderly realignment of MPC gas supplies.

D. NONCORE SERVICE OPTIONS

Noncore FUGC

The Plan provides that MPC will offer three types of service options to noncore FUGC customers: traditional fully-bundled cost-of-service based sales service (sales), rebundled market-priced sales subscription service (SSS) and unbundled transportation service (transportation).

Sales

Noncore FUGC customers could remain as sales customers of MPC. As sales customers they would be entitled to fully-bundled cost-of-service based gas service including cost-based gas supplies from MPC's embedded gas supply portfolio. This service would be comparable to the service these customers receive today and would be underpinned with a traditional utility obligation to serve. However, the service option will be contingent on a contract between MPC and the FUGC customer which would include a customer obligation.

SSS

Noncore FUGC customers may contract for the "rebundled" SSS offered by MPC. This service entitles them to a gas supply, priced to fluctuate with the competitive price of gas supplies in the open market, and to cost-based rebundled transportation features designed to accommodate the load characteristics of the specific customer. After the transition period, SSS would provide the noncore customer with an option to procure gas from MPC, but without the obligation to do so. On a month to month basis, SSS customers would be able to either buy their own gas supplies on the open market or purchase MPC's SSS gas supply. This flexibility will assure the gas supply commodity pricing inherent in SSS remains competitive in the market place. The customer's gas supply, if selected, would be delivered to the customer by MPC in accordance with "rebundled" transportation rates -- called SSS rates.

Transportation

Noncore FUGC customers may become transportation customers of MPC. As such, they would be responsible for procuring their own gas supplies and could contract with MPC for transportation of their gas supplies to their delivery points on MPC's system. Under this service option, these customers could select from the menu of unbundled transportation features (including transmission and storage functions) which they deem necessary to properly transport and shape their gas supplies for their requirements.

<u>Transitional Restrictions</u>

The Plan places certain restrictions on FUGC service options during the transition period. FUGC customers, other than one-third of GFG, will be considered sales customers for establishing the initial estimated rates computed in this Order.

In year 1, noncore FUGC customers would have the option, however, of converting up to one-third of their annual loads to either transportation or SSS. During year 2, noncore FUGC customers could convert up to two-thirds of their annual loads to transportation or SSS, and in year 3 noncore FUGC customers would have the option of converting their entire loads to SSS or transportation. GFG, as a party to the Stipulation Agreement, has elected to convert from sales to transportation service during the transition period. In accordance with the Stipulation, GFG must convert one-third of its load to transportation in year 1, two-thirds of its load to transportation in year 2 and 100 percent of its load to transportation in year 3. According to the Plan, MPC would not provide GFG sales service in year 3. GFG is prohibited from purchasing any SSS gas until the third year of transition, beginning September 1, 1993.

MPC will provide sales service to noncore FUGC customers for volumes which have never converted to either SSS or transportation. Noncore FUGC volumes departing from sales service, however, would subsequently only have the options of SSS or transportation; i.e. once any part of an FUGC customer's volume leaves sales service, it may not return to that option.

During the transition period, SSS customers do not have the option of displacing MPC's gas supplies on a month to month basis with supplies procured on their own behalf, although this flexibility is proposed to be in effect after the transition period.

Noncore End Users

Noncore end users would have two service options: SSS or transportation.

SSS

With the exception of SCC, all noncore end users are considered to be SSS customers for the purpose of establishing rates pursuant to this Order. The SSS option available to noncore end users is identical to the SSS option available to noncore FUGC customers. It is also subject to the transitional restrictions described in FOF 81 above.

Transportation

Noncore end users may elect transportation service, subject to the transitional restrictions described in FOF 81 above. Additionally, SCC has elected 100 percent transportation for the transition period pursuant to the Stipulation. With the inception of transportation, SCC will become a 100 percent transportation customer and will remain so for the duration of the transition period.

E. GAS MARKET/SUPPLY/COST

Pursuant to the Stipulation, MPC and parties to the agreement have proposed a $1.111/Mcf (14.9 psia, DBU level) gas cost for core customers in year 1. The gas cost was computed assuming all noncore end users remain as SSS customers of MPC except SCC, and that all noncore FUGC customers remain sales customers except GFG who will change from a sales customer to a transportation customer as set forth in FOF 86 above.

Seven Montana purchase contracts will be assigned from MPC to GFG and SCC to accommodate each customer's year 1, firm gas supply requirements and to mitigate core rate impacts. The proposed year 1 gas market, supply and cost are set forth at FOF 129, Table 4. A summary is contained in Table 1, attached.

F. REVENUE REQUIREMENT/RATE DESIGN

MPC's overall revenue requirement which results from the Plan, including the proposed gas supply cost agreed to in the Stipulation and the $6.2 million annual revenue requirement increase approved in Order No. 5484k (Docket No. 90.6.39), is $103,340,700. Of this amount, the residential class revenue requirement responsibility is $46,356,400 and the general service class revenue requirement responsibility is $32,706,600. The individual class revenue requirement responsibilities are set forth at FOF 146, Table 5.

The individual class revenue requirement responsibilities reflect the volumetric allocation of $26,343,335 fixed production costs to all customer classes except firm and interruptible transportation customers, as set forth in the Stipulation.

G. OTHER

MPC proposes to utilize a Gas Transportation and Adjustment Clause (GTAC) to track all interruptible on-system or Section 311 transportation revenues. The on-system interruptible volumes and sales proposed to be tracked in the GTAC are volumes of current or new customers which exceed normalized volumes recognized in Docket No. 90.1.1. Gas gathering and process ing services revenues, if such services are rendered and revenues are received, would also be tracked through the GTAC mechanism.

MPC proposes to track the difference between actual and estimated gas cost revenues and gas cost expenses, including the estimates for SSS, in the Unreflected Gas Cost Account.

The plan, as proposed by the parties, includes a guarantee on behalf of GFG and SCC that they will remain as MPC transportation and/or sales customers and will not bypass during the transition period.

H. COST OF SERVICE

The Stipulation, while fully cognizant of the substantial debates this Docket has engendered in both marginal cost analysis and reconciliation methods, does not offer confirmation to any side of those debates. The questions of proper cost estimation procedures and practical reconciliation methods remain open. The class revenue responsibilities, set forth in FOF 146, Table 5, were determined only by negotiation of the parties rather than by adoption or recognition of any cost of service methodology.

III. GAS TRANSPORTATION PLAN - COMMISSION ANALYSIS

A. CORE/NONCORE DISTINCTION-SERVICE OPTIONS

Discussion

MPC initially proposed that all present FUGC and Interruptible Industrial Gas Contract (IIGC) customers as well as all general service customers using over 60,000 Mcf per year be classified as noncore and be required to become transporters.

MPC argued that it should not be in the business of supplying gas to noncore customers, but only of supplying transportation service for the gas noncore customers procure. Mr. Johnson described how gas supply procurement on behalf of noncore customers represented a risk to core customers and MPC, with no opportunity for reward.

Dr. Tussing endorsed MPC's posture that noncore customers should not be allowed to buy price-regulated system gas whenever it was economically convenient for them to do so.

MPC conceded the noncore definition was arbitrary, basing the volume threshold on the historical threshold for IIGC customer status, but argued that it kept the initial number of eligible noncore customers at a manageable level while providing customers with the ability to procure their own gas supplies.

There was disagreement with the noncore definition MPC proposed. The DNRC witness Mr. Tubbs did not disagree with MPC's proposed noncore definition, and said,

> Residential and small commercial customers do not have the expertise or the time to directly buy gas from producers, and the costs of negotiating and administering small gas purchase and transportation contracts are likely to outweigh the small savings. (Exh. DNRC-1, p. 10)

Mr. Schneider, on behalf of SRS, objected to the noncore definition suggesting,

> ... artificial barriers such as the 60,000 Mcf annually or 600 Mcfd per customer should not be allowed to foreclose potential benefits to LIEAP customers. (Exh. SRS-1, pp. 12-13)

Mr. Schneider conceded that residential customers were the highest priority and that a direct purchase contains certain risk and thus "it may be advisable ... to allow partial requirements service by MPC ..." (Exh. SRS-1, pp. 14-15).

The MCC stated no position on the core/noncore definition, but maintained a position that noncore customers "should not be denied access to sales service" (Exh. MCC-7, p. 55).

MPC suggested in its October, 1990 filing that the definition of noncore customers be changed such that the two smallest customers presently taking service under the FUGC rate schedule, the Town of Kevin and Treasure State Pipeline, remain defined as core rather than noncore customers. Both these customers have consumption less than 60,000 Mcf per year. MPC's noncore definition remained unchanged thereafter in the Docket.

In MPC's October, 1990 filing, it did not concede, however, that noncore customers should have a choice between sales and transportation service. Dr. Tussing continued to dis cuss the conceptual reasons why he viewed a policy of regulated sales to noncore customers as unsatisfactory:

> Mr. Donkin's position directly conflicts with the central philosophy of the proposed restructuring, which is to draw a clear organizational line between functions that are inherently monopolistic or imbued with a special public service character, and those that are inherently or potentially competitive.

Dr. Tussing described two undesirable situations,

> ... that would make a regulated utility's bundled retail service more attractive to some noncore customers than comparable services offered by unregulated competitors.

He said either,

> |15 the Utility is subsidizing its sales of system gas to noncore customers, at the expense of core customers, or
>
> |25 it is discriminating against competing marketers in the quality of transport, balancing and storage services it offers them at a given price. (Exh. MPC-8, pp. 4-5)

The MCC maintained that noncore customers should be allowed a choice of sales or transportation service. MCC's witness Mr. Donkin, in his December, 1990 testimony, stated that a requirement for minimum term, minimum volume contracts and a gas inventory charge, or GIC, would address the gas supply uncertainty problems MPC had noted.

Dr. Power, on behalf of HRC, entered testimony in Docket No. 90.6.39 which conditionally supported MPC's core/noncore definition and the separation of competitive and regulated functions:

> This type of separation has the advantage of making clear what the Utility's obligations to various types of customers are. It also gets the Commission out of trying to set competitive prices." (Power p. 44, 12/90)

Dr. Power's reservations with MPC's Plan stemmed from his concern about the impact on core rates.

MPC revised its position of not offering noncore customers a sales or transportation option with testimony in its February, 1991 filing. The position it presented in its February, 1991 filing provided noncore customers the SSS option. Later testimony suggested MPC's perception of MCC's position on that issue was that unless noncore customers had a choice to become transportation customers, it was unlikely MPC would ever shed the gas supply obligation to those customers. MPC viewed an end to noncore gas supply obligations as a key feature of the transportation plan.

The Stipulation adopted MPC's definition of noncore customers which was never seriously challenged by any party.

The Stipulation directly addressed Mr. Schneider's concerns related to the transportation opportunities available for LIEAP loads. The Stipulation provided for a process to test the viability of such a service in conjunction with other State transportation programs.

The Stipulation essentially adopted the position the MCC had taken throughout the proceeding that noncore customers should be provided a choice between sales and transportation service. MPC had conceded that point in its February, 1991 tes timony in Docket No. 90.1.1. Parties to the Stipulation agreed that certain noncore customers should not have access to MPC system gas at cost, however. According to the Stipulation, noncore end users may purchase rebundled SSS or transportation services from MPC but not cost-of-service based sales service. Noncore FUGC customers may remain as sales customers indefinitely. Upon election of SSS or transportation, noncore FUGC customers are forever barred from cost-of-service based gas supply service as they know it today.

Commission Findings

The Commission agrees that it is important to initially keep the number and size of noncore customers manageable. Throughout the proceeding, no party seriously challenged MPC's "noncore" definition except as related to the LIEAP issue which was resolved in the Stipulation.

The Commission finds the definition of noncore customers adopted by the Stipulation is appropriate. That is, noncore customers shall be those current FUGC and general service customers who have test year consumption exceeding 60,000 Mcf, and all interruptible industrial customers. Using this definition, The Town of Kevin and Treasure State Pipeline shall fall in the core category and be entitled to FUGC sales service but will not have the option of converting to SSS or transportation.

The Commission believes MPC and core customers are subject to unfair and undue risk if noncore customers may elect cost-of-service based sales service whenever it is economically efficient for them to do so.

The Commission finds that the stipulation appropriately addresses its concerns that noncore FUGC customers not have the option of returning to sales service once they have departed in favor of SSS or transportation service.

The Commission finds noncore end users should have only a rebundled sales option in the form of SSS and/or a transportation service option.

B. GAS MARKET/SUPPLY/COST

Discussion

A significant issue throughout the duration of this Docket has been the impact of a market decline which is caused by noncore customers making a transportation election in favor of their own gas supplies. The market decline causes a significant imbalance between the gas supplies to which MPC has historically committed on behalf of noncore customers and that which MPC will require to serve its remaining customers. The gas supply imbalance problem tends to create a gas cost increase for core customers. MPC's witness, Ms. Schellin, presented the gas cost impact which core customers could expect from a loss of GFG and SCC loads, in MPC's January 10, 1990 direct testimony.

The case was presented as the Bypass Case in that filing. The core gas cost impact if GFG and SCC loads are lost would be the same whether the loss results from bypass or trans portation, if nothing is done to mitigate the impact. Table 2, attached, illustrates the market/supply and core gas cost impacts which the Company presented.

MPC computed the bypass gas cost impact using the assumption that it would continue to honor its take obligations under existing gas purchase contracts and market reductions would be met with reduced royalty gas takes. Table 2 illustrates the extent of required royalty gas cuts with the loss or conversion of GFG and SCC.

MPC based a proposal to redeploy certain of its royalty production assets on its ability to then mitigate the gas cost impacts of transportation relative to the Bypass Case. MPC's representation of the resulting core gas cost with MPC's Plan was $1.617/Mcf. This gas cost was $0.304/Mcf higher than the previously presented Base Case gas cost, but $0.038/Mcf lower than the gas cost expected with either bypass or transportation by GFG and SCC. (The balance of MPC's plan included further core rate mitigating nongas cost reductions which resulted from the redeployment.)

The MCC responded to MPC's representations of possible gas cost outcomes by questioning MPC's underutilization of royalty gas production and suggesting MPC's gas market should not be balanced with royalty gas. The MCC argued that royalty gas production should be maximized and that "Canadian and Montana purchase contracts ... be released and assigned by MPC to Entech." The MCC recommended a $19.4 million reduction in core customers' cost of service based on application of these suggestions to core gas cost.

MPC's October, 1990 Supplemental/Rebuttal Testimony updated all aspects of Docket No. 90.1.1, including the base case gas market, supply and gas cost, to coincide with MPC's general rate case, Docket No. 90.6.39, which was pending at the time. Ms. Schellin presented a comparison of the base case (business-as-usual) MPC market in her testimony. The overall result of this update on the base case and proposed transportation case gas market, supply and cost was set forth in Ms. Schellin's October, 1990 testimony.

A comparison of the base case gas market, supply and costs before and after updates is set forth in Table 3, attached.

In its October, 1990 testimony, MPC proposed two different gas costs; one applicable to customers taking service from the distribution system (DBU) and the other applicable to customers taking service from the transmission system (S&TBU). The gas cost difference between the two levels of service was totally related to the distribution level gas use and unaccounted for volumes (U&UAF) which apply to DBU level customers but not to S&TBU level customers.

MPC also presented extensive testimony relative to peak gas market and supply requirements on the MPC system in its October 10, 1990 testimony. The peak information was presented to address MCC suggestions that purchased gas contracts could be released or assigned in the manner MCC suggested and to make pipeline and storage capacity allocations.

The MCC responded to MPC's critique of its gas mix with testimony in December, 1990. Mr. Donkin presented evidence to support his conclusion that, if core customers retained access to all storage deliverability, MPC's arguments were not valid. Upon questioning by MPC about Mr. Donkin's exhibits and testimony, the MCC presented corrected peak day supply figures to replace Mr. Donkin's.

In MPC's February, 1991 testimony, Mr. Johnson set forth changes in MPC's proposal. He announced: 1) withdrawal of the plan to redeploy the CMG and CMPL properties to Entech, 2) the proposal to offer SSS to noncore customers, and 3) the proposal for sale of system surplus gas. System surplus gas sales were proposed as a way to dispose of excess gas supplies.

In her March, 1991 testimony, Ms. Schellin described the gas supply consequences of retaining the Aden properties and offering SSS and "system surplus" sales. For purposes of computing the gas cost, she assumed all noncore customers selected SSS except GFG and SCC. Additionally, she assumed 3 BCF of system surplus gas was sold. The assumed gas supply commodity prices of these sales, applied to the volumes assumed to be sold, generated credits which were proposed to be applied to core gas cost.

Column A, Table 4, attached, summarizes the proposed market, supply and gas cost in MPC's March, 1991 filing, considering SSS and system-surplus sales.

MPC's March, 1991 gas supply cost estimate was $1.418 (14.9 psia at distribution level) (Column A). This projection included gas cost credits of $132,547 for Canadian Utilities; $4,239,856 for sales under SSS; and $3,789,000 for system surplus sales.

The only customers projected to be transportation customers were GFG and SCC. All other noncore customers were presumed to receive service under SSS. MPC discussed the need to replace these projections with actual customer elections through an iterative process. The volumes assumed to be firm transportation volumes were also assumed to take firm storage service.

The gas supply costs to core customers were credited for system surplus sales of 3 Bcf at an estimated sales price of $1.263/Mcf, or a total of $3,789,000.

In its April, 1991 Rebuttal Filing, the MCC accepted MPC's Montana market assumptions but assumed surplus sales could be increased from MPC's 3 BCF/year to approximately 6.3 BCF/year. By doing so the MCC suggested additional royalty gas could be produced and thus the gas cost decreased from MPC's proposed level of $1.418/Mcf to $1.236/Mcf.

MCC's net projected gas supply cost was $1.236/Mcf (14.9 psia). This projection included gas cost credits of $132,500 for Canadian Utilities; $4,239,900 for SSS and $7,954,400 for System Surplus Sales.

MCC proposed a gas supply cost credit for system surplus sales of 6.3 Bcf, at a rate of $1.263 per Mcf, or $7,954,400.

The position was consistent with the arguments that higher royalty gas takes and lower purchase gas takes be included in MPC's gas mix as the MCC had proposed throughout the proceeding.

The gas market, supply and cost contained in the Stipulation resolves several of the parties' concerns. In accordance with the Stipulation, a noncore customer may, over a three-year period, make a transition from service which relies on MPC's gas supply to one of transport, wherein it would procure its own gas supply; or it may elect to stay as a SSS customer of MPC. In any event noncore customers will be required to enter into long-term contracts for the service elections they make. This transition requirement assures that MPC will not be saddled with high levels of gas supply which would result in either low rates of royalty gas take or high take-or-pay payments, both of which are financially unacceptable to certain parties.

The Stipulation provides for GFG to accept assignment of three Montana purchase contracts which are a part of MPC's gas supply portfolio. These assignments make firm transportation possible in year 1 for GFG; such transportation might not otherwise be possible due to the time required for firm transport customers to bring firm gas supplies on line.

Likewise, the Stipulation also provides that SCC will accept assignment of four Montana purchase contracts which are a part of MPC's gas supply portfolio in return for having the ability to transport 100 percent of its gas requirements beginning in year 1.

The parties' agreement that provided for a restriction on the volume of the market which can convert to transportation and assignment of gas purchase contracts was a turning point in this Docket. Taken together, those factors permit MPC to proportionately increase royalty gas levels above those previously proposed and reduce the gas cost.

Additionally, a relatively high level of SSS volumes, priced at market price and credited to core gas cost, is a mitigating factor for core rates.

The net projected gas supply cost resulting from the Stipulation Agreement is $1.083/Mcf (14.9 psia) at transmission level, and $1.111/Mcf (14.9 psia) at distribution level. This projection is the result of the assignment of purchase contracts on a permanent basis to GFG and SCC. Assignment of these contracts allows MPC to adjust its gas supply mix to better match its reduced market obligations and to mitigate the gas cost impact to core customers. This projection includes gas cost credits of $132,547 for Canadian Utilities and $3,837,224 for SSS, for the gas supply commodity portion of these sales. Because MPC has assigned purchase contracts to GFG and SCC, and because MPC will be supplying GFG two-thirds of its required volumes in addition to supplying the SSS customers' volumes from system supply during the first transition year, there will be minimal surplus supply available for surplus sales. Therefore, there is no gas cost revenue credit for surplus sales projected in the gas mix for the first transition year.

Commission Findings

The Commission believes MPC's efforts to produce high levels of royalty gas and thus reduce core gas cost by assigning existing purchase gas contracts pursuant to the Stipulation is appropriate. The Commission finds the Stipulation produces an acceptable core gas cost result by virtue of the transition restrictions, contract assignments and royalty gas production, and thus accepts the gas market, supply and cost set forth herein.

The Commission acknowledges that the year 1 core gas cost is sensitive to the date of transportation implementation and the volume of core sales. The Commission realizes the $1.111/Mcf gas cost is the estimate of the core gas cost if the core market assumptions contained in the Stipulation are correct and transportation were implemented for a full 12 months during year 1. The gas cost could be proportionately higher if lower core market volumes result from the iterative process or if transportation implementation would have occurred at a later date. For ratemaking purposes, the Commission approves $1.11/Mcf as the first year gas cost, however. The Commission finds that MPC must adopt gas cost strategies during each year to mitigate any upward pressure on gas rates. The Commission will review such strategies at the time of each annual filing. The strategies will be balanced against gas expenses to test whether any deferred amounts should be reasonably included in prospective rates.

The Commission finds it is appropriate to have rates reflect a gas cost which is applicable to the level of service from which the customer takes service (distribution or transmission). MPC should apply for, and incorporate into rates, gas costs which are reflective of the service level pertinent to that rate schedule. Gas cost differences for service at different levels of the system should be reflective of the gas UAF applicable to the distribution system, at a minimum. Other differences may be appropriate, but they must be consistent with FOF 144, above.

C. CLASS REVENUE REQUIREMENTS/RATE DESIGN

Discussion

Table 5, attached, below compares the class revenue requirements of MPC's March, 1991 filing (Column A); MCC's April, 1991 filing; (Column B) and the June, 1991 Stipulation Agreement; with both the $9.6 million revenue requirement increase request in Docket No. 90.6.39 (Column C) and the revenue increase approved under Order No. 5484k in Docket No. 90.6.39 (Column D). Although not contained in Table 5, DNRC witness Dr. Dodds recommended residential commodity charges of $3.1868/Mcf winter and $2.6254/Mcf summer. In conjunction with these commodity charges Dr. Dodds recommended that the Commission increase the monthly customer charge from roughly $4.15/month to $21.09/month.

MPC's 3/91 Proposal

MPC's total revenue requirement of $112,545,700 reflected in its March, 1991 filing included the $9.6 million annual revenue requirement increase request contained in its natural gas general rate case filing in Docket No. 90.6.39.

Although MPC's current rate structure reflects fixed (nongas cost) production function costs assigned to all customer classes on a volumetric basis, its March, 1991 filing reflected the assignment of all fixed (nongas cost) production function costs to its core customers (residential, general service and small utilities) or those customers MPC asserted would be using the production facilities under transportation. The total amount of fixed (nongas cost) production function costs in the March, 1991 filing were $27,789,804.

MPC's March, 1991 gas supply cost estimate was $1.418/Mcf (14.9 psia at distribution level). Table 4 sets forth the details of this gas cost computation.

MPC proposed to incorporate the low income discount for qualifying low income energy assistance (LIEAP) customers, the idea having been originally formulated by Mr. Thomas Schneider on behalf of SRS and agreed upon in Docket No. 90.6.39. Under MPC's proposal, residential, general service and small core utility customers were allocated their proportionate share of the low income discount effect on a uniform percentage of nongas costs basis.

MPC proposed a residential customer charge of $4.50/month and a general service customer charge of $9.50/month with the remaining revenue requirement of the core DBU customer class collected through a commodity charge of $4.352 per Mcf.

In the March, 1991 filing, the ST-FUGC-1 rate class included two small core utility customers whose annual volumes were less than 60,000 Mcf. MPC's proposed rate schedule retained the same rate structure which currently exists on the Firm Utility Gas Contract Rate Schedule, FUGC-1. The proposed unit rate was $6.044 per Mcf, which is almost double the rate these customers currently pay. CBG witness Mr. Whetstone argued that all small utilities should be deemed "firm non-interruptible core customers."

The only customers projected to be transportation customers were GFG and SCC. All other noncore customers were presumed to receive service under SSS. MPC discussed the need to replace these projections with actual customer elections through an iterative process. The volumes assumed to be firm transportation volumes were also assumed to take firm storage service.

The only on-system interruptible transportation volumes reflected in the March, 1991 filing were volumes of SCC in excess of their 100 percent load factor volume. This resulted in 1.8 Bcf firm transport volumes and 0.5 Bcf interruptible transportation volumes for SCC.

MPC proposed to establish a SSS class for service to those noncore customers who do not prefer to convert to transportation. Revenue credits for SSS were reflected in two parts. MPC proposed a procurement charge and brokerage fee for SSS with revenue credits for these charges reflected in the commodity portion of core customers' rates. The gas supply costs to core customers were credited for the commodity part of gas sales to SSS customers, as shown in Table 4.

MPC estimated 3 Bcf of Section 311 Transportation at an average transportation rate of $0.10 per Mcf. The resulting $300,000 revenue credit was reflected as a reduction to the transmission commodity rate for all core customers and firm transportation customers on the S&TBUs system.

MCC's 4/91 Proposal

The MCC recommended a total revenue requirement of $110,445,400 (Column B) in its April, 1991 filing which reflected the proposed annual revenue requirement increase recommended by MCC witness Mr. Clark in Docket No. 90.6.39.

The MCC recommended that fixed (nongas cost) production function costs be allocated to SSS customers on the same basis as was done for core market customers, i.e., on a volumetric basis. MCC argued it was appropriate to allocate these fixed production function costs to SSS customers using system supply. Otherwise, MPC, or far more likely its core market customers would have to bear the burden of those costs.

MCC allocated fixed (nongas cost) production function costs in a two-step procedure. Firm and interruptible transportation volumes were allocated production function costs equivalent to $0.20 per Mcf to reflect what MCC determined to be the proportionate share of the costs; the remaining fixed production function costs from MCC's cost study were allocated volumetrically to all sales customers, including the SSS customers.

MCC proposed a residential customer charge of $3.00/month and a commodity charge of $3.937 per Mcf and a general service customer charge of $5.50/month and a commodity charge of $3.847/Mcf. The MCC also reflected the 10 percent discount for qualifying LIEAP customers.

MCC's net projected gas supply cost was $1.236/Mcf (14.9 psia). Table 4, sets forth the details of this gas cost computation.

MCC estimated 6,298,000 Mcf of Section 311 transportation volumes at an average transportation rate of $0.20/Mcf in imputing revenues to Section 311 transportation volumes.

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The total revenue requirement of $106,510,600 (Column C) resulting from the June, 1991 Stipulation included the $9.6 million annual revenue requirement increase request reflected in MPC's natural gas general rate case filing in Docket No. 90.6.39.

The Stipulation assigned the fixed (nongas) production costs volumetrically to all customer classes (except firm transportation and interruptible transportation customers), similar to MPC's current rate structure. This resulted in core DBU customers (residential and small general service) being allocated $20.8 million instead of the $27.7 million assigned by MPC in its March, 1991 filing, and small utility customers being allocated $22,000 instead of the $30,000 assigned by MPC in that same filing. Per the Stipulation, the remaining firm utility volumes were allocated $3.6 million and SSS volumes were allocated $3.4 million. The Stipulation provides for an iteration which will give all SSS customers and noncore FUGC customers the opportunity to contract for transportation for up to one-third of their loads before the gas transportation plan is implemented. Further, the FUGC class will not be reallocated any of the additional fixed production costs which result from the iteration.

The net projected gas supply cost resulting from the Stipulation is $1.083 (14.9 psia) at transmission level, and $1.111 (14.9 psia) at distribution level. The details of this gas cost computation are set forth in Table 4.

In the Stipulation, the parties agreed to establish a first year residential customer charge of $4.00 and a general service customer charge of $9.50, with the remaining revenue requirement for the core DBU customers collected through the commodity charge. This rate, as reflected in the June, 1991 fil ing, was $3.838 per Mcf. Residential and general service customers rates reflect the low income discount effect. In correspondence to Commission staff (MPC Shellin letter 7-26-91), MPC forecast a high and a low residential and general service commodity rate for the last year of the transition, which, respectively, equal $4.16/Mcf and $4.232/Mcf.

The Stipulation provides for an FUGC class for service to the same utility customers currently served by MPC under Rate Schedule FUGC-1. The rate structure proposed for service to FUGC customers includes a monthly service charge, a reservation charge, and a commodity charge. The average rate for each customer served in this rate class is dependent on the customer's load factor, but the resulting rates are at or about the FUGC class rate level proposed in MPC's general rate case filing in Docket No. 90.6.39.

The Stipulation reflected only GFG and SCC as transportation customers. All other noncore customers were presumed to receive service under SSS. The Stipulation sets forth the need to replace these projections with actual customer elections through an iterative process. The volumes assumed to be firm transportation volumes were also assumed to take firm storage service.

The interruptible transportation volumes reflected in the Stipulation are the volumes of SCC which exceed their 100 percent load factor firm volume. This situation could be affected by the iterative process.

The Stipulation accepts the SSS class and, during the transition period, limits the option of customers served under this rate class to elect up to one-third of their volumes to change to transportation in the first transition year, up to two-thirds of their volumes to change to transportation in the second year, and all their volumes to change to transportation in the third year.

In its March, 1991 filing, MPC proposed a two-part Reservation Rate for SSS; one for utility system demand and one representative of the gas supply reservation charge MPC would experience on other pipeline systems to secure the capacity needed to serve SSS customers. MPC also proposed to allow the SSS customers the option of securing their gas supplies in the market place each month or be served by MPC from system supplies, depending on price. The Stipulation continues to provide for a two-part reservation rate, but dictates that, during the transition period, all SSS volumes will be supplied by MPC at market price, as proposed by MPC.

The Stipulation establishes an estimated 6 Bcf of Section 311 volumes at an average transportation rate of $0.10 per Mcf. The resulting $600,000 revenue credit is reflected as a reduction to the commodity rate for all core customers and all firm transportation customers on the S&TBU's system. All interruptible transportation volumes, either Section 311 or on-system, will be tracked and adjusted during the transition period according to the GTAC. The on-system interruptible volumes and sales proposed to be tracked are those of either current or new on-system customers which exceed the volumes reflected as normalized test year volumes in Docket No. 90.1.1.

Stipulation Agreement - Impact of Final Order No. 5484k

The final column of Table 5 shows the class revenue requirements resulting from the Stipulation when updated for the annual revenue requirement increase authorized in Docket No. 90.6.39, Order No. 5484k.

The total revenue requirement of $103,340,700 reflected in Column D includes the $6.2 million annual revenue requirement increase approved by the Commission in Docket No. 90.6.39, Order No. 5484k.

The reduced annual revenue requirement approved in Order No. 5484k affects the various revenue requirement components. The fixed production costs of $27.8 million which were allocated to the core DBU and S&TBU customers in MPC's March, 1991 filing, and subsequently reassigned to the gas supply customers pursuant to the Stipulation, are $26.3 million, when updated for Order No. 5484k in Docket No. 90.6.39. These fixed production costs were reassigned volumetrically to all customer classes (except firm transportation and interruptible transportation customers) in the manner agreed to in the Stipulation. The results are $19,731,228 fixed production costs allocated to core DBU customers (residential and small general service), $21,391 allocated to the small utility customers, $3,354,255 allocated to the remaining firm utility volumes, and $3,236,461 allocated to SSS volumes.

The net projected gas supply costs, the gas cost credits, and the Section 311 transportation revenue credits resulting from the Stipulation remain unchanged.

The residential customer charge is set at $4.00/month and the general service customer charge is set at $9.50/month. The remaining revenue requirement for the core DBU customers is collected through the commodity rate of $3.722/Mcf. Residential and general service customers' rates reflect the 10 percent low income discount effect.

The rates which result from incorporating the $6.2 million revenue requirement increase approved in Order No. 5484k and the provisions of the Stipulation (which include assigning fixed production costs to all gas supply volumes; reduced gas costs of $1.083/Mcf (14.9 psia at transmission level); and revenue credits for 6 Bcf of Section 311 transportation volumes at an estimated rate of $0.10 per Mcf) are set forth in Attachment 6 to the Stipulation.

Commission Findings

The Commission finds the class revenue requirements which result from applying the stipulated allocation of costs to the revenue requirement resulting from Order No. 5484k, when combined with the gas supply cost reduction produced by the stipulated gas market, supply and cost, are just, reasonable and acceptable.

The Commission finds that a residential customer charge of $4.00/month, pursuant to the Stipulation is just and reason able and MPC will incorporate this rate into its residential rate calculation.

The rates discussed in FOF 178 above are the representative rates noncore customers should use to make their initial service elections. Once these customers have made their elections, MPC will recalculate the rates to be filed for approval by the Commission; these rates will incorporate the iteration necessary to reflect the volumes moving to transportation which affect the fixed production cost allocation.

The gas cost set forth in Table 4 is accepted for the first transition year.

The FUGC rate structure discussed in FOF 167 and set forth on Attachment 6 to the Stipulation is approved for inclusion on Rate Schedule ST-FUGC-1.

D. GAS TRACKING ADJUSTMENT CLAUSE - (GTAC)

Discussion

In its March, 1991 filing, MPC proposed to utilize the GTAC to track the difference between (1) the estimated SSS procurement and brokerage fee revenues as reflected in that filing and the actual revenues received; and (2) the estimated Section 311 transportation revenue in that same filing and the actual revenue received, all on an annual basis. MPC proposed to amortize the difference between these estimated and actual revenues in the subsequent 12 months. MPC also proposed to reflect any gas gathering and processing services revenues, if such services are actually rendered and revenues are actually received.

In its March, 1991 filing, MPC's proposed SSS consisted of a monthly service charge per delivery meter; subscription fees of (a) a reservation charge of $5.65 per MDDQ for utility system capacity and (b) a procurement charge of $7.50/MMcf/day for gas supply reservation; commodity charges per MMbtu of (a) $0.253 for transportation on the transmission system, (b) $0.378 for transportation on the distribution system (if applicable), (c) market priced gas supply, and (d) a brokerage fee of 5 percent of the market priced gas supply cost.

The Stipulation revised the SSS proposal by eliminating the brokerage fee and providing for gas supply only from MPC's system gas supplies during the transition period. The proposed transition rate structure consisted of the same monthly service charge per delivery meter as proposed in the March, 1991 filing. The Stipulation also retains the same subscription fees as described in FOF 185 above. However, since MPC is going to be the sole gas supplier for SSS during the transition period and SSS customers will not have the option of going out to the market place, the $7.50/MMcf/day procurement charge is intended to be one of the rate elements on the SSS Rate Schedule which recovers the SSS customers' revenue requirement responsibility. The Stipulation sets forth commodity charges for transportation on the transmission and distribution (if applicable) systems and provides for a market-priced gas supply cost, as established by an acceptable procedure. The commodity price, which will be the same for all SSS customers, will be set each month at a price that MPC believes reflects the spot market. That price will be established by surveying producers and marketers who stand ready to sell gas. In addition, the transmission charge reflects this class proportionate share of the fixed production cost allocation.

The revisions to the SSS proposal, as proposed in the Stipulation, eliminated the need to track the $7.50/Mcf/day procurement charge through the GTAC during the transition period. However, MPC continues to propose to track all on-system or Section 311 interruptible transportation revenues, through the GTAC mechanism. The on-system interruptible transportation volumes and sales proposed to be tracked through the GTAC are volumes of either current or new customers which exceed the volumes reflected as normalized test year volumes in Docket No. 90.1.1. Gas gathering and processing services revenues, if such services are rendered and revenues are received, would also be tracked through the GTAC mechanism.

The Stipulation projects estimated Section 311 transportation of 6 Bcf at an average rate of $0.10 per Mcf. The Stipulation provides for tracking and adjusting these estimated interruptible Section 311 (or on-system interruptible sales transportation volumes which are in excess of the normalized on-system volumes included in the Docket) during the transition period according to the GTAC. The MCC agreed that the GTAC was appropriate on an interim basis.

In its March, 1991 proposal, MPC proposed gas supply cost credits for sales to SSS customers and for system surplus sales. In the Stipulation, gas supply cost revenue credits are only reflected for SSS sales.

In Order No. 4598, the Commission approved MPC's annual Unreflected Gas Cost Tracking procedure (Deferred Gas Cost Accounting). MPC will track the difference between actual and estimated gas cost revenues and gas cost expenses for all customer classes reflected in its projected gas cost calculation through the Unreflected Gas Cost Tracking procedure. This includes the gas cost credit for the gas commodity portion of SSS. Gas supply sales affecting the net gas supply costs to core customers will continue to be tracked through the Deferred Gas Cost Account. MPC proposed to file its annual Gas Cost Tracking Filing, which includes the Deferred Gas Cost Account Balance, concurrently with its GTAC filing.

Commission Findings

The Commission approves the proposed GTAC mechanism, as set forth in the Stipulation and FOF 184 to 190. MPC shall use the GTAC to track the differences between the estimated amount of revenue from off-system, Section 311 transactions and the actual revenues. The Commission finds that 6 Bcf of Section 311 transportation volumes at the average interruptible transportation rate of $0.10 per MMBTU is a reasonable basis for the estimate of the revenue which may be generated by this activity in the upcoming year, and represents a compromise between MPC's proposed estimate and the MCC's proposed estimate. The Commission encourages MPC to maximize these sales to the extent possible given the constraints of the transmission system and the marketplace and approves the GTAC as a method to enable core customers to realize the benefits of these transactions as soon as possible and to protect MPC from under recovery until experience is gained with Section 311 transportation.

The Commission finds the proposed SSS rate structure, as set forth above in FOF 186, is appropriate during the transition period.

The difference between actual gas cost revenue and actual gas cost expense for all customer classes reflected in MPC's projected gas cost calculation, including the gas cost credit for the gas supply portion of SSS, will be handled through MPC's annual Unreflected Gas Cost Tracking procedure.

E. SINGLE ISSUE FILINGS

Discussion

In year 1 of the transition, one-third of GFG's volumes will convert to transportation. All other noncore FUGC customers, as well as SSS customers will have the option of converting up to one-third of their loads to transportation.

As discussed in FOF 164, MPC will compute the effect the year 1 conversion iteration has on rates proposed for sales customers in this Order and submit final rates for approval.

In year 2, an additional one-third of GFG's volumes will convert to transportation and noncore FUGC customers and SSS customers will have the option of converting up to two-thirds of their volumes to transportation.

In year 3, the last third of GFG's volumes will convert to transportation and noncore FUGC and SSS customers will have the option of converting all of their loads to transportation.

The Stipulation provides for a single issue filing during each year of the transition which will include new sales and SSS tariffs based on reallocation of the fixed (nongas cost) production function costs associated with the year 2 and 3 conversions, to volumes of core sales and SSS customers. It also provides that the only issue to be addressed in MPC's annual single issue filing is whether MPC has properly determined the volumes that have converted to transportation, and thus whether MPC has properly reallocated the fixed production costs to the remaining sales volumes, excluding the FUGC customers.

Commission Findings

The Commission determines that it is appropriate to allocate, on a timely basis, the fixed production costs associated with the conversion of system gas supply customers' volumes to transportation service. It is appropriate that those custom ers using system supply gas pay reasonable fixed production costs associated with that supply. The Commission will allow MPC to submit annual filings to reflect the system gas supply volumes expected to convert to transportation for the subsequent 12 months and the fixed (nongas) production function cost reallocation associated with these conversions. The filings should also satisfy the requirements of FOF 69 and 144. Notification of annual filings must be served on all appropriate parties.

F. LOW INCOME DISCOUNT

Discussion

On April 12, 1991, in PSC Docket No. 90.6.39, the Commission received the Stipulation Regarding Low Income Discount (Low Income Stipulation) entered into by the MPC, MCC, HRC, and SRS (attached as Appendix 7). In part, the parties to the Low Income Stipulation agreed that MPC's proposed ten percent discount, as described in the prefiled rebuttal testimony and exhibits in Docket No. 90.6.39, is the appropriate low income rate proposal for purposes of the proceeding.

The parties to the Low Income Stipulation further agreed to review other low income utility matters, including, but not limited to the Energy Assurance Plan proposal of HRC; incorporating a level-of-poverty matrix, based on family size and income; incorporating LIEAP benefits directly into rates; targeting low income weatherization; and other low income programs, as proposed by the parties.

Commission Findings

Upon consideration of the proposed Low Income Stipulation regarding the 10 percent low income discount issue in Docket No. 90.6.39, the Commission finds that it provides a reasonable solution to the areas of disagreement between the parties and finds that the Low Income Stipulation promotes the public interest. Therefore, the Commission approves MPC's proposed 10 percent low income discount for qualifying low income customers. The revenue shortfall created by this discount should be collected from all core DBU customers.

The additional issues agreed to by the parties in the Low Income Stipulation should be reviewed by MPC, and MPC should address any further issues in its next cost-of-service filing.

G. WAIVER OF FILING REQUIREMENTS

Discussion

During the first two years of the transition period, MPC agreed to retain the cost allocations and rate designs adopted by the Stipulation. The agreement provides that no party to the Stipulation would object to a waiver of the filing requirements for allocated cost-of-service and rate design if MPC files for an overall revenue requirement increase with the Commission. If MPC files for, and the Commission approves, a general revenue requirement increase, such increase will be applied on an equal percentage basis to the nongas cost revenues.

Commission Finding

The Commission finds that the filing requirements waiver provision of the Stipulation is reasonable to allow for rate stability during the transition period.

H. IMR AND NGI CONTRACTS

Discussion

In its January, 1990 filing in Docket No. 90.1.1, MPC testified that it specifically targeted elimination of the IMR and NGI Rate Schedules with the implementation of transportation.

In its response to PSC Data Request 03-204, MPC pointed out that for the IMR Rate schedule, the tariff would no longer be available for annual renewal upon expiration of the IMR customer's contract year (or in MSU's case, contract term), since the Service Year Definition under the IMR Rate Schedule states that "service under the

Schedule is eligible for renewal annually." For the NGI Rate Schedule, the Term of the Schedule is 1), a) until April 20, 1991, or b) as long as gas resources are available at terms that will allow the utility to feasibly serve the additional load in such a manner that the utility and its customers will benefit; whichever comes first: and 2) to Canbra Foods, Ltd. (Canbra) until December 31, 1994.

On April 11, 1991 MPC filed an application for approval to extend its NGI Rate for a period of one year beyond the current expiration of April 20, 1991. On May 1, 1991 the Commis sion issued a Notice of Commission Action granting the extension of the NGI tariff for the account presently served (Louisiana Pacific) until April 20, 1992, or until the transportation service in Docket No. 90.1.1 is approved by the MPSC and implemented by MPC, whichever occurs first.

MPC is bound by legal contract to continue service to MSU under the IMR Rate Schedule until February 1, 1993, unless MSU chooses and MPC agrees to convert to one of the services under the Transportation Plan. MPC is bound by legal contract to offer NGI service to Canbra until December 31, 1994, unless Canbra revises its contract.

Commission Findings

The Commission finds that availability of the IMR and NGI Rate Schedules is discontinued. Those customers currently being served under these Rate Schedules will be served only to the extent provided for under their current contracts with MPC. Those customers who have the option to continue to receive service under the IMR and NGI Rate Schedules, in accordance with their current contracts, may choose to remain service customers under these Rate Schedules for the term of their current contract, or, subject to contractual limitations, to elect to switch their entire load to services provided under MPC's transportation proposal. No loads may be served as partial IMR or NGI volumes and partial transportation volumes.

I. REMAINING IMR AND DEFERRED ACCOUNTING BALANCES

Discussion

In its initial filing in January, 1990 and again in its rebuttal filing in October, 1990, MPC proposed to amortize existing Deferred Account and IMR Recovery balances from all existing customer classes, since these existing amortizations are the responsibility of, or for credit to these current customers. MPC proposed to include amortization of these balances on all DBU and S&TBU core rate schedules and the S&TBU's transportation rate schedules until the existing balances have been extinguished. Once the existing balances have been extinguished, MPC proposed to eliminate the amortization on the transportation rates schedules. Unreflected Gas Cost Account Balances resulting after the transition to transportation, would be the responsibility of only those sales customers who continue to require an annual gas supply. The unit amortization amounts would be reflected as an adjustment to the commodity portion of rates set forth on all applicable rate schedules.

Commission Findings

The Commission finds that it is appropriate to amortize all existing Unreflected Gas Cost Account and IMR Recovery Balances from or to the current customers being served by MPC under jurisdictional rate schedules. The current Unreflected Gas Cost Account and IMR Recovery Balances being amortized on MPC's current rate schedules, as well as the balances that are being booked in the current Gas Tracking years, will be amor tized and reflected on all DBU and S&TBU core rate schedules and the S&TBU's transportation rate schedules, until they have been extinguished. Unreflected Gas Cost Account Balances resulting after the transition to transportation will be the responsibility of those sales customers who continue to require an annual gas supply.

J. INTERRUPTIBLE TRANSPORTATION

Discussion

In its October, 1990 filing, MPC proposed to use the 100 percent load factor firm transportation rate as its maximum interruptible transportation (IT) rate. MPC stated that FERC has found such rates to be just and reasonable. MPC proposed to discount its maximum IT rate only if 1) the shipper can demonstrate a more economic alternative (see FOF 61); and 2) there is under-utilized capacity on the facilities necessary to provide the service. In its March, 1991 filing, MPC proposed that this maximum IT rate be calculated from the 100 percent load factor firm transportation rate without the credit for ST-ITG-1 net revenues. The ST-ITG-1 net revenues resulted from reducing the IT revenue recovery (the revenue recovery realized from applying the 100 percent load factor IT rate to the interruptible transportation volumes) by the revenue requirement assigned to the IT group in the cost of service calculation.

The MCC proposed an IT rate of $0.60 per Mcf, if MCC's proposed annual revenue requirement recommendation were adopted by the Commission. This IT rate included the $0.20 per Mcf contribution to fixed transmission and/or storage costs proposed by the MCC.

SCC's witness Mr. Michael recommended flexibly priced IT rates within a range of cost-of-service based floor and ceiling rates. Mr. Michael recommended the ceiling price for the IT commodity rate be set at the embedded cost based on Mr. Maxwell's cost-of-service study.

The Stipulation set forth the estimated rates for all proposed rate schedules. These rates were to be revised to reflect the change in the revenue requirement as a result of the final Order in Docket No. 90.6.39. The rates set forth on Attachment 6 of the Stipulation Agreement for IT service are the 100 percent load factor firm transportation rates, without credit for the net IT revenue, as proposed in MPC's March, 1991 filing.

Commission Findings

Because the parties who set forth IT rate proposals have agreed to the representative rates as set forth on Attachment 6 to the Stipulation, the Commission finds that the 100 percent load factor firm transportation rates, without credit for the IT revenues, are the appropriate rates for maximum interruptible transportation service, and MPC should calculate its proposed IT rates in this manner. The Commission fully intends to revisit this issue in MPC's next cost-of-service filing. The Commission approves MPC's proposal to restrict discounting the maximum rate as set forth in FOF 213.

K. GENERAL TERMS AND OPERATING CONDITIONS (GT&C)

Discussion

MPC submitted Exh. MPC-46, Rate Schedule No. GTC-1, entitled General Terms and Operating Conditions, into evidence during the course of the hearing in Docket No. 90.1.1. It replaced Exhibit ___(DEW-6SR) in Exh. MPC-42 which had previously replaced this rate schedule attached in Appendix B to the original Application. Much of the proposed Rate Schedule No. GTC-1 was uncontested throughout the Docket. The Sections that are at issue are Section 15, Balancing, and the penalty provisions included therein, and the requirement for contracting and nominating on point-to-point specific receipt and delivery point basis, pursuant to Section 18.4, General Operating Provisions.

Balancing

Balancing is the process of keeping volumes delivered from the transmission system concurrent with volumes received into the transmission system. Balancing is necessary to prevent shippers from taking volumes received into the S&TBU's system on behalf of other shippers and to allow the S&TBU to maintain control of its system. Balancing provisions also prohibit transportation customers from taking advantage of some of the S&TBU's services, such as storage, for which they have not paid.

Initially, MPC proposed daily balancing and that a penalty rate be imposed for daily imbalances.

SCC witness Dr. Roy Shanker objected to the daily balancing requirement and suggested that monthly balancing was more appropriate. Dr. Shanker also argued that the penalty rate should not be tied to the average storage commodity cost because MPC had not demonstrated that it actually incurred this cost as a result of balancing.

MPC responded to SCC testimony and made an alternative proposal in its October, 1990 filing. The proposal incorporated monthly balancing (as opposed to daily balancing) and retained Balancing Penalty Rates for those shippers who became significantly out of balance at any time and failed to correct the situation within 48 hours after receiving notice. When the system is stressed, MPC proposed that it have the authority to refuse or adjust receipts and/or deliveries in order to force shippers into balance. MPC proposed to charge for imbalances based on total monthly confirmed nominations. If the shipper's cumulative monthly imbalance at the end of the month was equal to or less than 4 percent of its total monthly confirmed nomination, there would be no balancing charge. According to the proposal, cumulative monthly imbalances which, at the end of each month, are greater than 4 percent and equal to or less than 10 percent of total monthly confirmed nominations, would be billed by multiplying that imbalance by the Balancing Rate contained in the applicable rate schedule. If the cumulative imbalance exceeds 10 percent and the shipper fails to bring the balance back within the 10 percent tolerance within 48 hours of notice, negative imbalances in excess of 10 percent would be subject to the Balancing Penalty Rate contained in the applicable rate schedule. Volumes equivalent to positive imbalances in excess of 10 percent would be retained by MPC at no cost and free and clear of any claims.

MPC did not change the derivation of the Balancing Penalty Rate stating that it is intended to be sufficiently punitive to discourage the use of system supply or other shipper gas as a substitute for storage service or backup supply sources.

Dr. Shanker was satisfied with the changes made by MPC except for the level and intent of penalty payments.

Rate Schedule GTC-1, Section 15 on Balancing was adopted as part of MPC's Transportation Plan in Paragraph 1 of the Stipulation Agreement.

Point to Point Nominations

Pursuant to Section 18.4 of the Rate Schedule GTC-1, shippers must request (nominate) volumes at the Point(s) of Delivery and Receipt for firm and interruptible transportation and storage for the upcoming month. MPC proposed point-to-point specific transportation because the MPC system is a complex grid of transmission lines with a great number of potential receipt and delivery points that must be carefully controlled to fairly manage the fullest utilization of system capacity. MPC stated that as more experience is gained with transportation, with shippers' requirements and with the capability of the system, MPC may allow more flexibility in receipt/delivery controls. Dr. Tussing also testified that it is understandable for MPC to desire to gain operational experience before offering more flexibility in receipt and delivery points. However, he also testified that MPC and all customers would benefit from enhanced flexibility because of the greater utilization of the pipeline that it fosters, particularly during the off-peak season when capacity constraints on the delivery system are unlikely to exist and changes in the receipt and delivery points are most readily accommodated.

GFG objected to the point-to-point requirements, suggesting the requirement would limit its gas supply flexibility. Mr. Geske, on behalf of GFG, argued that restricting the amount of gas that can be taken from each source may force a shipper into buying higher priced gas from one source than it would have to buy at another. More flexibility could provide for the basic needs of customers in case of an emergency if there were problems with a source of supply. Mr. Geske requested more flexibility only to the extent that capacity was available on the system.

In response to intervenors' concerns about the lack of flexibility with the point-to-point constraint in its original proposal, MPC proposed additional flexibility. To the extent that receipt points are on the same system segment and/or present no significant operational problems, MPC, in its sole discretion, will accept requests for transportation that lists multiple receipt points for a single delivery point. When multiple receipt points are used, the balancing requirements could also be met on a pooled receipt basis relating to the specific delivery point.

The parties to the Stipulation specifically resolved this issue in Paragraph 11. The parties agreed that MPC's proposal was acceptable until year 3 (which begins September 1, 1993) at which time the matter would be revisited. During the first two transition years, MPC agreed to work with shippers in the event of an emergency and the need for temporary alternative receipt points arose. The offer is subject to other MPC obligations and the availability of system capacity. Further, the Stipulation states that if additional costs are incurred by MPC in the provision of such flexibility, the shipper must pay them. MPC does not agree to provide backup gas supply.

Commission Findings

The Commission finds that the operating terms and conditions set out in Rate Schedule No. GTC-1 have been agreed on by the parties to the Stipulation and, in the Commission's opinion, represent a reasonable and prudent manner of conducting the gas transportation business and are approved.

L. OTHER OPERATING MATTERS

Discussion

Firm Capacity Allocation

MPC originally proposed to allocate firm transmission capacity to noncore customers up to a 600 Mcf maximum daily limit. Nearly all noncore customers expressed an interest in contracting for some level of firm transportation service and believed that the limit MPC proposed was too low to accommodate their needs. MPC subsequently changed its proposal and proposed to initially allocate firm transmission capacity (and distribution capacity where applicable) to noncore customers in amounts up to their actual consumption on February 2, 1989. The February 2, 1989 actual consumption reflects the level to which industrial customers were able to curtail under peak conditions. The resulting actual peak day usages are thus MPC's best measure of the firm capacity needs of these customers.

MPC's proposal provided for the reallocation of uncontracted firm transmission space to other firm customers requesting additional firm capacity. Such reallocation was to be at the sole discretion of MPC. In cases where customers contract for both firm and interruptible service, all the gas will flow through a single meter and firm volumes will be deemed to be first through the meter. The maximum quantity of firm transmission, distribution and storage capacity to which noncore customers may contract, are set out in MPC Exh. 42 (DEW-3SR).

DNRC witness Dr. Dodds suggested alternative methods of allocating firm capacity to be used once MPC and shippers have gained experience with transportation. The objective of these methods would be to allocate capacity to the highest valued uses and to give MPC a signal whether investment in additional capacity is economically justified.

With the proposal of SSS by MPC, MPC further specified that the total quantity of firm services previously identified would be the total amount to which a customer could contract for through SSS and/or firm transportation service.

MPC's proposal regarding the allocation of firm transmission capacity did not change further and was agreed on by the parties to the Stipulation.

Gathering and Processing Services

MPC did not propose a rate schedule for gathering and processing services because there is no significant Montana production (not already flowing into the MPC system) which will be seeking gathering or processing service after transportation is implemented. MPC proposed to deal with any requests for such service on an ad hoc basis and flow the rate impact of any gathering and processing revenues to the core customers via the GTAC. If enough demand materializes for gathering and processing services, MPC will then propose a gathering and processing rate schedule.

In response to questions from intervenors, MPC testified that gathering and processing costs are currently included in production function costs. Gathering and processing facilities are presently segregated from transmission facilities at the point of final compression into a transmission pipeline and anything upstream of final compression is considered gathering and processing.

Service Agreements

As part of its proposed Gas Transportation Plan, MPC proposed several service agreements that must be executed between MPC and a shipper before service will be provided by the S&TBU. These agreements are attached to MPC Exh. 42, as follows:

-Firm Gas Transportation Service Agreement
Exhibit __(DEW-9SR)

-Interruptible Distribution Service Agreement
Exhibit__(DEW-10SR)

-Interruptible Gas Transportation Service Agreement
Exhibit __(DEW-11SR)

-Firm Gas Storage Service Agreement

An additional service agreement was introduced into evidence separately during the hearing as Exh. MPC-45, Firm Sales Subscription Natural Gas Service Agreement.

None of the service agreements MPC proposed were specifically contested by any party in Docket No. 90.1.1 and are agreed on as part of MPC's Gas Transportation Plan, pursuant to Stipulation.

Aggregation of LIEAP Customers

A consequence of MPC's designation of customers as either core or noncore is that all customers that do not meet the criteria for noncore status must continue to receive their gas supply from MPC as a fully-bundled service. MPC retains its obligation to procure gas supply and serve core customers.

MPC's Rate Schedule GTC-1 also requires nomination of a single delivery point and does not provide for multiple delivery points.

Mr. Schneider, on behalf of SRS, argued that the State of Montana should have the ability to acquire gas supplies on behalf of the LIEAP clients on MPC's system. He argued that the designation of noncore customers created an artificial barrier that should not be allowed to foreclose the opportunity to aggregate small residential loads to purchase off-system gas supply.

MPC responded by stating that MPC's plan provided the potential for the state or some other aggregator to fulfill the role Mr. Schneider explained. The suggestion required study and evaluation and MPC suggested that it would be willing to discuss the possibilities at some time following the initial implementation of gas transportation.

SRS responded by requesting the Commission to preserve the opportunity for the State of Montana to aggregate the gas loads of LIEAP gas customers for possible direct purchase on behalf of LIEAP clients. SRS proposed that all customers should have the option of selecting core or noncore status under any gas industry restructuring approved by the Commission.

The parties to the Stipulation reached an agreement on this issue, it is set out in Paragraph 12 of the Stipulation. The Stipulation states that MPC's previous proposal regarding core/noncore status and multiple delivery points is acceptable for beginning the implementation of Gas Transportation. However, the parties further agreed that providing non-discriminatory open access to other customers through lowering the threshold and allowing aggregation and multiple delivery points may provide benefits to certain customers and MPC and should not be precluded from this. Therefore, the parties committed to proceed to jointly develop, test, evaluate, and if feasible, finalize and file alternative policies with the Commission. The details of the procedures are set out in Paragraphs 12.a. to 12.e. of the Stipulation.

Commission Findings

The Commission finds that the issues discussed in FOF 231 through FOF 245 are either uncontested or have been resolved by the parties contesting these issues in the Stipulation. Therefore, the Commission approves of these parts of MPC's Gas Transportation Plan and/or the Stipulation.

IV. THE ALLOCATED COST OF SERVICE

A. DISCUSSION

Organization of Findings

During the course of this Docket, the transportation proposal has gone through several changes; so too have the proposed allocated cost-of-service analyses. The organization of these findings is intended to summarize the final positions of the various parties to this Docket and to describe the evolution of the parties' positions where change has occurred over the course of this Docket.

The beginning point for comparison is the March 9, 1990 supplemental testimonies of Dr. James Falvey and Ms. Karen Schellin. This filing initiated the discussion of allocated marginal cost of service among the parties to this Docket. The initial January 10, 1990 allocated cost-of-service analysis (Embedded Cost Study) will be briefly described first, but only in order to document the full extent of the record; once described it will be ignored thereafter.

The various marginal cost of service analyses performed will first be split into two distinct parts. The pure or full (unmoderated) marginal cost analyses (Pure Marginal Cost Study) will be described by functional area of cost causation (supply, storage, transmission, distribution) and each party's position will be stated. Then, the problems involved in the moderation of pure marginal costs to the revenue requirement and the positions taken by the various parties to this Docket will be discussed (Reconciliation of Marginal Costs to Embedded Costs). Quantification of moderated marginal costs will be noted where provided.

<u>The Embedded Cost Study</u>

MPC's initial filing in Docket No. 90.1.1 included an allocated cost-of-service study sponsored by Mr. Philip E. Maxwell. Mr. Maxwell's objectives were stated in his testimony:

a. the splitting of costs of service between the separated parts of the utility after the proposed restructuring of assets and operations, and;

b. the costing of the new menu of services that were proposed in that filing.

This allocated cost study began with a total cost of service from a 1987 test year of $104,093,142. This total was split between the restructured gas utility (RGU) ($91,113,692) and the proposed redeployed Canadian properties and activities.

The RGU's total costs of service were apportioned among supply, storage, transmission and distribution in the amounts of $48,809,595; $8,087,785; $15,385,969; and $18,704,805, respectively. An additional $108,514 from CMPL-Reagan and $17,023 from CMPL-Carway were also included in the RGU.

The RGU's costs were classified to peak demand, winter commodity, summer commodity and customer costs in the amounts of $17,463,381, $39,738,133, $20,596,292 and $13,315,890, respectively.

The allocated cost study in the January 10, 1990 filing was an embedded cost study; functionalized, embedded, classified costs were allocated to service offerings by each service offering's share of those classified costs.

This procedure produced the following unit revenue requirements for the various service offerings assuming 1987 test year revenue requirements and loads:

Core Customers		$4.947
Noncore Firm Transporters:		
Distribution Level	$0.985	
Transmission Level	$1.013	
Noncore Interruptible Transporters:		
Distribution Level	$0.885	
Transmission Level	$0.329	

Core customers were the only customers using utility supply sources under the proposal embodied in the January 10, 1990 filing; this cost study assigned all production-related costs to core customers.

The Pure Marginal Cost Study

Most parties to this Docket analyzed the structure of marginal gas costs, although in some cases that analysis was brief. Only the most significant points will be noted herein.

Marginal Supply Costs

MPC's initial estimate of marginal gas supply costs appeared in the March 10, 1990 Supplemental Filing. It was a levelized calculation of estimated real (1991 $) gas cost over a 20-year period (1991 - 2010) and resulted in a cost of $2.472 per Mcf.

In reaction to this filing, the DNRC provided reasoning that a single year's current cost provided a more realistic estimate of marginal gas supply costs. MPC's subsequent filings accepted this reasoning and for the remainder of the Docket MPC's estimate of marginal supply cost was $1.77 per Mcf. DNRC never explained why a single year's 1991 gas cost would best serve to ration scarce resources over the three to four years beyond 1991 during which this cost would be the basis of rates. Neither did MPC explain how a 1991 gas cost would efficiently allocate scarce gas resources during the time period (1992-1995) in which this cost would be the basis of rates. MPC asserted, without proof, that the $1.77/Mcf is not simply a short run marginal cost, but embodied producers' evaluation of future market prices, a point which some parties contested. MPC's single marginal supply cost figure was not seasonally differentiated.

In his May, 1990 filing, MCC witness Mr. Drzemiecki utilized MPC's March, 1990 (corrected) real levelized 20-year estimated gas price figure of $2.436 per Mcf as his estimate of the marginal gas commodity cost. This figure represented levelized estimates of real gas prices through the year 2010. Mr. Drzemiecki retained this $2.436 per mcf estimate of marginal commodity costs in subsequent filings. Mr. Drzemiecki stated that his preference for long run marginal commodity cost was due to the complimentary relationship between the gas commodity and consumer durable goods.

In May, 1990, DNRC witness Mr. John Tubbs sponsored testimony relevant to cost-of-service questions. His testimony presented comments on several areas of MPC's cost-of-service analysis, but did not comprehensively quantify marginal cost estimates. Mr. Tubbs did propose a marginal supply cost estimate of $1.77 per mcf to emphasize the present day commodity costs. Mr. Tubbs also proposed that commodity costs were, and rates should be, seasonally differentiated.

Subsequent to the initial filing, DNRC testimony was sponsored by Dr. Daniel Dodds. Dr. Dodds' initial testimony was filed in December, 1990. His marginal commodity cost was based on MPC's (altered) estimate of $1.77 per mcf. Dr. Dodds adjusted this figure upward to produce a winter season marginal cost estimate of $2.06 and a summer season marginal cost estimate of $1.77 per Mcf.

DNRC also concluded, without proof, that the present price estimate of $1.77 per Mcf was not simply a short run marginal cost but contained future price expectations. DNRC did state that Dr. Falvey's weak statement -- that current prices have a connection with expected future prices -- requires no necessary assumptions.

The testimony of GFG witness Mr. Bruce Ambrose did not specifically review the estimates of full marginal cost provided by MPC.

SCC witness Mr. Jan Michaels did not specifically address the estimates of marginal commodity costs provided by MPC.

Cost-of-service and rate design testimony was presented by HRC witness Dr. Thomas Power. Dr. Power stated that the marginal cost of the commodity was between $2.44 per mcf and $0.20 per mcf. He interpreted the $2.44 figure (MCC's figure) to be an average of real prices of new gas over the next ten years and the $0.20 figure to be MPC's royalty gas costs. Dr. Power recommended that the Commission use long run incremental costs as embodied in the $2.44 per Mcf figure. It appeared that much of Dr. Power's concern with the use of short run commodity costs was his belief that present gas prices are at a point well below expected future prices.

Marginal Storage Costs

MPC produced marginal storage cost estimates from an analysis of operations at the Cobb Storage Field. These estimates were based upon a cushion gas-to-deliverability ratio of approximately 118 Mcf; i.e., it required additional pressure equivalent to an injection of 118 Mcf to produce one more mcf of deliverability per day. The estimate was based upon deliverability/pressure data generated during the February, 1989 extreme weather conditions.

Peak day needs dominated the operation of storage and so did peak day costs; marginal peak day deliverability costs were estimated to be $34.01 per Mcf per day and marginal seasonal deliverability was estimated at $0.34 per Mcf.

MPC altered these marginal storage cost estimates in the October, 1990 Supplemental and Rebuttal Testimony. Two corrections were made: first, the cushion gas inventory valuation was reduced from $2.47 per Mcf to $1.77 per Mcf; and second, the return on cushion gas inventory was increased from 11.46 percent to 15.7363 percent to include taxes. These changes reduced marginal storage cost to $32.87 per Mcf per peak day and $0.29 per seasonal Mcf.

MPC acknowledged that as the storage drilling program progresses, the marginal peak day storage costs are likely to fall, but rebutted Dr. Power's February 14, 1991 testimony that the 118 to 1 ratio of cushion gas to incremental design deliverability should be rejected.

The MCC's estimate of marginal storage deliverability costs started with MPC's stated cushion gas to deliverability ratio of 118 Mcf. The cushion gas was valued at $2.436 per Mcf and a return of 11.46 percent was specified. This produced a dollar storage carrying cost of $32.94.

MCC witness Mr. Drzemiecki added two additional small charges ($0.99, $3.26) to derive "Annual Marginal Cost per Mcf of Storage Capacity" of $37.19. He then reclassified one-half of these costs and all remaining storage O&M expenses to winter season storage costs.

DNRC witness Dr. Dodds used MPC's estimate of marginal peak deliverability of $32.87 peak Mcf per day. He used this figure in spite of some misgivings. He also included an injection and withdrawal marginal cost of $0.0345 per mcf and $0.0403 per Mcf, respectively.

HRC witness Dr. Power did not provide a specific marginal storage cost estimate, but did offer criticism of MPC's derivation of marginal storage costs. He disagreed with the $1.77 per Mcf valuation of cushion gas and states that a lower value should be used. Dr. Power was not convinced that MPC's modeling of gas storage requirements was correct, but seemed to agree that it may be the best that is presently available.

In later testimony, Dr. Power indicated that there were other internal analyses done by MPC which indicated a much lower marginal gas storage cost than that produced by Dr. Falvey.

Marginal Transmission Costs

MPC estimated marginal transmission costs by modeling the cost of changes in transmission investments and operations that would be required to serve additional load in the Missoula service area. This led to marginal transmission costs which were based upon adding and operating a compressor at Main Line No. 1. The resulting estimates were initially $14.85 per peak day mcf and $0.004 per Mcf off peak.

MPC noted that the estimates of marginal transmission costs were influenced by the location of the incremental load served. MPC also noted that the main contribution of this approach was to produce a usable split between marginal peak and marginal off peak costs; this split (ratio of peak to off peak) was essentially unaffected by the load location utilized. The instability of such estimates based on location of loads is surely a candidate issue for MPC's next cost-of-service filing.

Final MPC estimates of marginal transmission costs were $13.52 per design peak day mcf and $0.0661 per off peak Mcf.

MCC began with the same model of incremental capacity additions used by MPC and determined a capital cost of new compression of $75.43 per mcf. In his initial filing in Docket No. 90.1.1, Mr. Drzemiecki multiplied this capital cost by a carrying cost of 11.46 percent and then added a fixed O&M and a fuel component to reach a figure of $10.62 per Mcf of transmission capacity.

In his December testimony, Mr. Drzemiecki again started with MPC's capital cost estimate of $75.43 per Mcf. To this he applied a carrying cost of 17.84 percent together with a $.58 per Mcf fixed O&M adder to yield a cost of $14.04 per Mcf of capacity. Mr. Drzemiecki's estimate of marginal cost per Mcf of capacity remained at $14.04 per Mcf for the remainder of the Docket. This was conceptually and numerically close to MPC's estimate of transmission capacity marginal costs; unlike MPC, Mr. Drzemiecki did not appear to provide an estimate of off peak marginal transmission costs.

DNRC witness Mr. Tubbs questioned MPC's estimate of marginal transmission costs because the majority of those costs consisted of the cost of capacity expansion. Mr. Tubbs doubted that the transmission system was, in fact, capacity constrained.

In his December, 1990 testimony, DNRC witness Dr. Dodds used MPC's estimate of marginal capacity costs of $13.46 per Mcf. In the same filing, Dr. Dodds produced an estimate of off peak transmission marginal costs of $0.1594 and $0.0610 per mcf for core customers in winter and summer respectively; the corresponding numbers were $0.0703/Mcf and $0.0610/Mcf for noncore customers.

Dr. Dodds' estimate differed from Dr. Falvey's due to: (1) DNRC's correct inclusion of use and unaccounted for volumes in costs which Dr. Falvey relegated to in-kind payments; (2) inclusion of peak day capacity in off peak costs; and (3) seasonal differentiation.

HRC witness, Dr. Power, confined himself to general criticism of MPC's marginal cost approach. He believed that MPC's marginal cost studies exclude some relevant marginal costs.

Marginal Distribution Costs

MPC noted in its initial marginal cost filing that the matching of the concept of marginal costs to operational reality was probably most difficult in the distribution function.

While noting misgivings, Dr. Falvey estimated marginal distribution costs from the forecast costs of nine major distribution projects. This approach produced estimates of $59.42 per peak Mcf and $0.55 per off peak Mcf, after splitting the distribution investment equally between peak and off peak usage.

Subsequently, Dr. Falvey abandoned the direction taken in his March, 1990 testimony; his abandonment was based on his belief that (1) using estimates of new project costs yields an average cost (of new projects) figure, not a marginal cost result, and (2) as designed, distribution systems can accommo date additional load without additional investment. This change in approach was noted in the initial allocated cost of service testimony filed in Docket No. 90.6.39 and was adhered to through the remainder of that docket and this one. This final approach resulted in estimated marginal distribution costs of $.0443 per Mcf both off and on peak.

MCC witness Mr. Drzemiecki stated that the marginal distribution cost (and marginal customer costs) were not as important as marginal gas service costs. Gas service costs were defined by Mr. Drzemiecki to be equal to the total of the commodity, storage and transmission functions. Because of this view, Mr. Drzemiecki did not provide estimates of marginal distribution costs and instead worked from embedded distribution costs.

DNRC witness Mr. Tubbs stated that capacity charges should not be included in the calculation of marginal distribution costs. Dr. Dodds' estimates of marginal distribution costs were $0.0443 per Mcf which matched those of Dr. Falvey; however, they were not understood to be the same by Dr. Dodds.

HRC witness Dr. Power did not specifically address distribution costs.

Marginal Customer Costs

The estimate of customer costs provided by MPC consisted of two pieces. The first was the levelized estimated cost of the meter, regulator and fittings. The second was the estimated annual customer accounting expense, customer-related distribution expense and customer-related general expense for the Kalispell district (Kalispell consists of MPC Gas Service only). These two pieces were estimated to total $15,236,782 and were estimated to be $145 per year per core customer; $27,224 per year per firm utility customer; $4,021 per firm customer served on the distribution system; and $17,904 per year per interruptible customer. These numbers remained, except for minor adjustments, constant through the entire Docket No. 90.1.1 and Docket No. 90.6.39.

MCC witness Mr. Drzemiecki treated customer costs in the same manner as he treated distribution costs and worked from embedded cost numbers.

DNRC witness Dr. Dodds' computed customer costs from data in MPC's filing. However, Dr. Dodds did note clear reservations about using these data. The reservations stemmed from the belief that MPC's customer cost estimates were really estimates of average costs and a belief that there were inconsistencies in MPC's description of the responsibility of new large customers to pay for hook up and metering costs.

HRC witness, Dr. Power, fundamentally disagreed with the approach MPC used to calculate customer costs, particularly if that approach was proposed to be a marginal cost approach. He characterizes much of MPC's method as a fully distributed approach and noted that a truly marginal approach would yield substantially lower cost results.

Reconciliation of Marginal Costs to Embedded Costs

At the same time, all parties should note that the choice of the most appropriate reconciliation method, like costing methods, has stirred an understandable debate in this Docket, given the recent application of marginal costing to gas utilities in Montana. Therefore, in light of the doubts that have been raised about the overall question of reconciliation, at this juncture, it is worth noting the sources of differences separating the parties and describing the methods each espoused.

MPC witness, Dr. Falvey, described his reconciliation of marginal cost to the embedded revenue requirement as functional equiproportional marginal cost (FEPMC) reconciliation. It differed from typical EPMC reconciliation methods in that it was functionally segmented and was applied one function at a time. For example, the production function embedded costs were spread to those taking production according to the estimated marginal costs of production; the embedded storage costs were spread to those taking storage service according to the estimated marginal costs of storage, and so on for each function. The FEPMC procedure was described first in the March, 1990

Supplemental Testimony of Docket 90.1.1. This procedure was repeated in Docket 90.6.39 and an expanded explanation and justification was provided there.

The most complete explanation of MPC's FEPMC was contained in MPC's October, 1990 Supplemental and Rebuttal Testimo ny. Dr. Falvey emphasized the role of cost causation and the separate nature of the production, storage, transmission and distribution activities and consequently the separability of costs of each of these activities. Prior to unbundling, the functions were separable only on the cost (supply) side; given unbundling, they became separable on both the demand and the supply side. Dr. Falvey held his method prevents inadvertent cross-subsidization.

Dr. Falvey also provided a resource allocation argument for function-by-function reconciliation in his October testimony and concluded that: "... only if consumers demonstrate their willingness to pay the total costs of providing that service is continuation of the activity (together with the investment in replacement facilities required through time) unambiguously efficient." The term "total cost" was meant by Dr. Falvey to be total economic costs, not embedded costs. In his view, embedded costs were simply the real world approximation of total costs.

Although several parties disagreed with Dr. Falvey, no party made as convincing an argument as Mr. Ambrose. Mr. Ambrose "absolutely positively" disagreed with Dr. Falvey's likening embedded costs to the economist's real world approximation of total costs. In fact, Mr. Ambrose conceded that GFG could be allocated embedded costs over and above MPC's marginal cost of serving GFG without causing GFG to uneconomically bypass MPC. With Dr. Falvey's FEPMC core customers would bypass MPC by possibly increasing their use of wood to heat space.

MCC witness Mr. Drzemiecki described his overall approach as maintaining the embedded cost functionalization and used long-run marginal costs as the means to classify the functionalized costs between demand and commodity. Thus, his reconciliation of marginal costs to embedded costs, like the MPC methodology, was based on a function-by-function cost reconciliation. Unlike the Company's method, however, it was not an equal percentage of marginal cost method.

In Mr. Drzemiecki's opinion, not all functions' marginal costs were equally important. The most important functions were production, storage and transmission; these three were in combination, defined as "gas service" by Mr. Drzemiecki.

Mr. Drzemiecki's reconciliation methodology followed his view of the relative importance of marginal costs. He reconciled each of his important marginal costs (production, storage, transmission) to each of their functional embedded cost totals. For his two lesser functions (distribution and customer) he avoided the reconciliation problem completely by rejecting marginal costs altogether and using embedded costs from the out-set. Although this was functional reconciliation, it was distinctly different from that used by MPC.

Because Mr. Drzemiecki used embedded distribution and customer costs, there was no need to reconcile these functions. Mr. Drzemiecki spread the production revenue requirement to cus tomer classes based upon test year class Mcf usage. This was accomplished by multiplying usage amounts by marginal supply costs ($2.436/Mcf) and then multiplying the resultant figure by a factor of 0.9274 to reach his production revenue requirement number of $61,283,438. This reconciliation assigned the production function revenue requirement to all customer classes as if all customers would continue purchasing gas from the restructured utility; this was accomplished by assigning production costs to them that they would have borne absent transportation.

The reconciliation method used for the storage cost function was best explained in Mr. Drzemiecki's December, 1990 Testimony. Mr. Drzemiecki, prior to reconciliation, had a total estimated marginal storage capacity cost of $7,176,971 to reconcile to an embedded storage cost number of $7,510,079. The reconciliation was accomplished by subtracting $834,368 ($5.95 per Mcf times 140,230 Mcf) of fixed O&M from the marginal storage capacity costs ($7,176,971). The resulting $6,342,603 was then divided by two (2) to yield $3,171,302. This number was shown on the fifth line of Exhibit __ (JD-14) p. 1 of 4 as "LONG-RUN COSTS, STORAGE DEMAND." The reconciliation to embedded costs was completed by subtracting this number ($3,171,202) from total storage embedded costs ($7,510,079) and classifying the difference ($4,005,669) as "LONG-RUN MARGINAL COSTS, STORAGE WINTER COMMODITY." By thus subtracting marginal capacity costs from the embedded cost and calling the difference marginal commodity costs, reconciliation of the total of the two pieces to embedded costs was guaranteed.

MCC's reconciliation to embedded transmission costs followed a somewhat different path. Total marginal transmission capacity costs of $3,392,232 were calculated. This figure was reduced by $0.58 per Mcf of fixed O&M to yield a figure of $3,252,098 which was labelled "LONG-RUN MARGINAL COSTS, TRANSMISSION DEMAND"; the difference ($15,175,389) between this number and the embedded revenue requirement number ($18,427,487) was denoted as "LONG-RUN MARGINAL COSTS AT THE SALES REVENUE REQUIREMENT, TRANSMISSION COMMODITY," thus completing the reconciliation by subtraction.

Although he did not condemn equiproportional adjustments to reconcile marginal costs to the revenue requirements, DNRC witness Dr. Dodds did not support exclusive use of EPMC reconciliation in this case. His rejection was based on an alleged distortion that is introduced by EPMC when marginal costs are substantially different from embedded costs, as they were in this proceeding.

Dr. Dodds noted two other reconciliation methods that might be used: one was to raise the customer charge by roughly 400 percent to absorb much of the difference; the second was to use block rates. He also discussed regressivity and other problems the two methods face.

In the end, Dr. Dodds appeared to choose a combination of reconciliation methods which combined a high customer charge with an EPMC allocation of the remaining (after subtracting the high customer cost) difference between marginal cost and embedded revenue requirement. Although Dr. Dodds ultimately rejected MPC's FEPMC in favor of total EPMC, he did add that he believed the entire question of reconciliation methodology needed further study and should be revisited by the Commission in a future proceeding.

HRC witness Dr. Power's view of the reconciliation was best described in his comments about MPC's and others' reconciliations. His conclusions were that MPC's proposal to reconcile marginal costs to embedded cost by separate functional cost categories results in utility prices bearing a variable and arbitrary relationship to marginal costs. This undermines the primary objective of marginal cost pricing, namely efficient resource use and turns the marginal costs analysis largely into an embedded cost analysis. He argued that an embedded cost analysis is inappropriate because "number crunching" of cost data will not yield rational utility rates. The Commission's policy objectives and judgments must guide the selection and use of cost information. He further argued that the equal percentage of marginal cost (EPMC) method of reconciling marginal and embedded costs <u>can</u> be challenged on equity grounds when substantial embedded investment costs get ignored in the marginal cost analysis.

GFG witness Mr. Ambrose, much like DNRC, advocated an EPMC reconciliation based upon the total marginal costs and the total embedded revenue requirement (Total EPMC) throughout this Docket. Mr. Ambrose, like Dr. Power, testified, that an FEPMC reconciliation is little more than a disguised embedded cost allocation. Total EPMC was judged by Mr. Ambrose as a second best solution. His preferred solution was inverse elasticity or Ramsey pricing, but because this method required extensive information on demand elasticities, he said it was not practical to apply it in this proceeding. Use of the Total EPMC implicitly assumes all demand elasticities are equal, according to Mr. Ambrose. EPMC equates to inverse elasticity pricing when all demand elasticities are equal.

Mr. Ambrose's testimony also discussed the variation in the percentage of original cost to price ratios assigned to various activities through the rates charged for the various services. He noted that core customers paid 97.1 percent of marginal costs while the firm utility transporters were asked to pay 452.5 percent of marginal cost.

SCC witness Mr. Michael, in his May, 1990 testimony, also criticized MPC's FEPMC. His criticisms were twofold: first, he believed MPC's approach violated the spirit of previous Commission Orders; second, he believed the functional EPMC method reduced the study to an embedded cost result.

B. COMMISSION ANALYSIS AND CONCLUSIONS

The Commission finds that the Stipulation renders moot the questions about proper marginal costing, including reconcil iation methodology. The Commission's acceptance of the Stipulation <u>does not</u> constitute support for, or acceptance of, any particular reconciliation method, marginal cost analysis, including cost classification and allocation, e.g. NCP.

The Commission attributes much of the debate to the relatively recent application of marginal costing to the gas industry in Montana. The debate is an important one, and can not be simply ascribed to differences in self-interest.

While accepting the Stipulation, the Commission encourages a full discussion of both marginal cost issues and reconciliation methodology in the next gas allocated cost of service study filed by MPC following the transition period.

CONCLUSIONS OF LAW

All Findings of Fact are hereby incorporated as Conclusions of Law.

The Montana Power Company provides natural gas service within the State of Montana and as such is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission within the meaning of Section 69-3-101, MCA.

The Montana Public Service Commission properly exercises jurisdiction over MPC's rates and operations pursuant to Title 69, Chapter 3, MCA.

The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Sections 69-3-303, 69-3-104, MCA, and Title 2, Chapter 4, MCA.

Gas Transportation is approved for implementation on the Montana Power Company's system and is determined to be in the best interest of the public.

The rate levels and design approved herein are just, reasonable, and not unjustly discriminatory. Sections 69-3-303 and 69-3-201, MCA.

ORDER

THEREFORE, THE MONTANA PUBLIC SERVICE COMMISSION ORDERS THAT:

The Stipulation Agreement among MPC, MCC, GFG, SCC, DNRC, HRC, and SRS concerning implementation of gas transportation and corresponding rates in Docket No. 90.1.1 is approved as expressed herein.

Montana Power Company is hereby ordered to abide by the provisions of the Stipulation Agreement as approved and discussed in the above Findings of Fact and Conclusions of Law.

In accordance with the Stipulation Agreement as approved in this proceeding, Montana Power Company must provide all noncore end-users and the noncore FUGC customers with the opportunity to contract for gas transportation for up to one third of their annual loads in the first transition year. Upon completion of this process, Montana Power Company shall submit a final iteration of the proposed rates, derived using the method ology proposed in the Stipulation Agreement and herein, by October 15, 1991.

Gas transportation shall begin on MPC's system on November 1, 1991.

DONE IN OPEN SESSION at Helena, Montana, this 26th day of September, 1991, by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Chairman

DANNY OBERG, Vice Chairman

BOB ANDERSON, Commissioner

JOHN B. DRISCOLL, Commissioner

WALLACE W. "WALLY" MERCER, Commissioner

ATTEST:

Ann Peck
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See ARM 38.2.4806.